UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 30, 2010

o Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

Commission file number 1-9735

BERRY PETROLEUM COMPANY
(Exact name of registrant as specified in its charter)

DELAWARE	**77-0079387**
(State of incorporation or organization)	(I.R.S. Employer Identification Number)

1999 Broadway, Suite 3700
Denver, Colorado 80202
(Address of principal executive offices, including zip code)

Registrant's telephone number, including area code: **(303) 999-4400**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES x NO o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES o NO o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES o NO x

As of July 21, 2010, the registrant had 51,206,925 shares of Class A Common Stock ($.01 par value) outstanding. The registrant also had 1,797,784 shares of Class B Stock ($.01 par value) outstanding on July 21, 2010 all of which is held by an affiliate of the registrant.

BERRY PETROLEUM COMPANY
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BERRY PETROLEUM COMPANY
Unaudited Condensed Balance Sheets
(In Thousands, Except Share Information)

	June 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$ 239	$ 5,311
Short-term investments	65	66
Accounts receivable, net of allowance for doubtful accounts of $0 and $38,508, respectively	140,866	74,337
Deferred income taxes	4,006	5,623
Derivative instruments	7,557	11,527
Prepaid expenses and other	11,707	6,612
Total current assets	164,440	103,476
Oil and gas properties (successful efforts basis), buildings and equipment, net	2,343,568	2,106,385
Derivative instruments	6,676	735
Other assets	26,398	29,539
	$ 2,541,082	$ 2,240,135
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 78,902	$ 63,096
Revenue and royalties payable	23,234	25,878
Accrued liabilities	24,530	29,320
Line of credit	3,300	—
Derivative instruments	23,570	33,843
Total current liabilities	153,536	152,137
Long-term liabilities:		
Deferred income taxes	302,065	237,161
Senior secured revolving credit facility	310,000	372,000
8¼% Senior subordinated notes due 2016	200,000	200,000
10¼% Senior notes due 2014, net of unamortized discount of $12,284 and $13,456, respectively	437,716	436,544
Asset retirement obligation	49,313	43,487
Other long-term liabilities	18,709	19,711
Derivative instruments	29,646	75,836

		2010		2009
		1,347,449		1,384,739
Shareholders' equity:				
Preferred stock, $.01 par value, 2,000,000 shares authorized; no shares outstanding		—		—
Capital stock, $.01 par value:				
Class A Common Stock, 100,000,000 shares authorized; 51,206,925 and 42,952,499 shares issued and outstanding, respectively		512		430
Class B Stock, 3,000,000 shares authorized; 1,797,784 shares issued and outstanding (liquidation preference of $899)		18		18
Capital in excess of par value		319,771		89,068
Accumulated other comprehensive loss		(52,928)		(60,372)
Retained earnings		772,724		674,115
Total shareholders' equity		1,040,097		703,259
	$	2,541,082	$	2,240,135

The accompanying notes are an integral part of these condensed financial statements.

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income (Loss)
Three Months Ended June 30, 2010 and 2009
(In Thousands, Except Per Share Data)

	Three months ended June 30,			
		2010		2009
REVENUES AND OTHER INCOME ITEMS				
Sales of oil and gas	$	151,525	$	118,793
Sales of electricity		7,928		6,624
Gas marketing		5,004		4,848
Realized and unrealized gain (loss) on derivatives, net		56,057		(31,130)
Settlement of Flying J bankruptcy claim		21,992		—
Interest and other income, net		1,796		806
		244,302		99,941
EXPENSES				
Operating costs - oil and gas production		46,452		34,738
Operating costs - electricity generation		7,839		6,397
Production taxes		5,064		4,885
Depreciation, depletion & amortization - oil and gas production		43,703		34,371
Depreciation, depletion & amortization - electricity generation		793		1,028
Gas marketing		4,357		4,232
General and administrative		12,155		13,164
Interest		16,340		10,589
Extinguishment of debt		—		10,492
Transaction costs on acquisitions		1,908		—
Dry hole, abandonment, impairment and exploration		266		17
Bad debt recovery		(38,508)		—
		100,369		119,913
Income (loss) before income taxes		143,933		(19,972)
Provision (benefit) for income taxes		54,910		(7,204)
Income (loss) from continuing operations		89,023		(12,768)
Loss from discontinued operations, net of taxes		—		(212)
Net income (loss)	$	89,023	$	(12,980)
Basic net income (loss) from continuing operations per share	$	1.65	$	(0.28)
Basic net income (loss) per share	$	1.65	$	(0.28)
Diluted net income (loss) from continuing operations per share	$	1.64	$	(0.28)
Diluted net income (loss) per share	$	1.64	$	(0.28)
Dividends per share	$	0.075	$	0.075

Unaudited Condensed Statements of Comprehensive Income (Loss)
Three Months Ended June 30, 2010 and 2009
(In Thousands)

Net income (loss)	$	89,023	$	(12,980)
Unrealized losses on derivatives, net of income taxes of $0 and ($44,776), respectively		—		(73,055)
Reclassification of realized gains on derivatives included in net income, net of income taxes of $0 and ($5,708), respectively		—		(9,314)
Accumulated other comprehensive loss amortization of de-designated hedges, net of income taxes of $2,478 and $0, respectively		4,044		—

Comprehensive income (loss)	$ 93,067	$ (95,349)

The accompanying notes are an integral part of these condensed financial statements.

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Income (Loss)
Six Months Ended June 30, 2010 and 2009
(In Thousands, Except Per Share Data)

	Six months ended June 30, 2010	2009
REVENUES AND OTHER INCOME ITEMS		
Sales of oil and gas	$ 299,332	$ 246,662
Sales of electricity	17,861	16,895
Gas marketing	13,276	12,429
Realized and unrealized gain on derivatives, net	57,661	6,034
Settlement of Flying J bankruptcy claim	21,992	—
Interest and other income, net	1,960	1,088
	412,082	283,108
EXPENSES		
Operating costs - oil and gas production	93,488	72,122
Operating costs - electricity generation	17,509	15,179
Production taxes	10,269	10,537
Depreciation, depletion & amortization - oil and gas production	79,609	70,769
Depreciation, depletion & amortization - electricity generation	1,588	1,987
Gas marketing	12,142	11,516
General and administrative	25,990	26,457
Interest	33,788	20,639
Extinguishment of debt	—	10,494
Transaction costs on acquisitions	2,635	—
Dry hole, abandonment, impairment and exploration	1,636	140
Bad debt recovery	(38,508)	—
	240,146	239,840
Income before income taxes	171,936	43,268
Provision for income taxes	65,244	14,258
Income from continuing operations	106,692	29,010
Loss from discontinued operations, net of taxes	—	(6,991)
Net income	$ 106,692	$ 22,019
Basic net income from continuing operations per share	$ 2.01	$ 0.63
Basic net loss from discontinued operations per share	$ —	$ (0.15)
Basic net income per share	$ 2.01	$ 0.48
Diluted net income from continuing operations per share	$ 2.00	$ 0.63
Diluted net loss from discontinued operations per share	$ —	$ (0.15)
Diluted net income per share	$ 2.00	$ 0.48
Dividends per share	$ 0.15	$ 0.15

Unaudited Condensed Statements of Comprehensive Income (Loss)
Six Months Ended June 30, 2010 and 2009
(In Thousands)

Net income	$ 106,692	$ 22,019
Unrealized losses on derivatives, net of income taxes of $0 and ($51,773), respectively	—	(84,472)
Reclassification of realized gains on derivatives included in net income, net of income taxes of $0 and ($29,083), respectively	—	(47,452)
Accumulated other comprehensive loss amortization of de-designated hedges, net of income taxes of $4,563 and $0, respectively	7,444	—
Comprehensive income (loss)	$ 114,136	$ (109,905)

The accompanying notes are an integral part of these condensed financial statements.

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BERRY PETROLEUM COMPANY
Unaudited Condensed Statements of Cash Flows
Six Months Ended June 30, 2010 and 2009
(In Thousands)

	Six months ended June 30, 2010	Six months ended June 30, 2009
Cash flows from operating activities:		
Net income	$ 106,692	$ 22,019
Depreciation, depletion and amortization	81,197	74,944
Extinguishment of debt	—	10,494
Amortization of debt issue costs and net discount	4,218	2,578
Dry hole and impairment	1,428	9,643
Unrealized (gain) loss on derivatives	(46,110)	8,287
Stock-based compensation expense	5,008	4,980
Deferred income taxes	61,142	8,090
Loss on sale of oil and natural gas properties	—	330
Other, net	—	(4,963)
Cash paid for abandonment	(1,535)	(176)
Allowance for bad debt	(38,508)	—
Change in book overdraft	2,007	(24,988)
Increase in current assets other than cash and cash equivalents	(33,176)	(7,982)
Decrease in current liabilities other than book overdraft, line of credit and fair value of derivatives	(7,494)	(44,076)
Net cash provided by operating activities	134,869	59,180
Cash flows from investing activities:		
Exploration and development of oil and gas properties	(135,038)	(73,126)
Property acquisitions	(150,674)	(11,668)
Capitalized interest	(13,054)	(12,626)
Proceeds from sale of assets	—	138,597
Net cash (used in) provided by investing activities	(298,766)	41,177
Cash flows from financing activities:		
Proceeds from issuances on line of credit	159,200	248,500
Payments on line of credit	(155,900)	(273,800)
Proceeds from issuance of 10¼% senior notes	—	304,025
Long-term borrowings under credit facility	165,000	586,275
Repayments of long-term borrowings under credit facility	(227,000)	(937,176)
Debt issue costs	—	(21,508)
Financing obligation	(169)	—
Dividends paid	(8,083)	(6,831)
Proceeds from issuance of common stock, net	224,313	—
Proceeds from stock option exercises	1,156	87
Excess tax benefit and other	308	67
Net cash provided by (used in) financing activities	158,825	(100,361)
Net decrease in cash and cash equivalents	(5,072)	(4)
Cash and cash equivalents at beginning of year	5,311	240
Cash and cash equivalents at end of period	$ 239	$ 236

The accompanying notes are an integral part of these condensed financial statements.

Berry Petroleum Company
Notes to Condensed Financial Statements

1. Basis of Presentation

These Condensed Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) for interim financial reporting. All adjustments which are, in the opinion of management, necessary to present fairly Berry Petroleum Company's (the Company) financial position at June 30, 2010 and December 31, 2009 and results of operations and comprehensive income (loss) for the three and six months ended June 30, 2010 and 2009, and its cash flows for the six months ended June 30, 2010 and 2009 have been included. Interim results are not necessarily indicative of expected annual results because of the impact of fluctuations in prices received for oil and natural gas, as well as other factors. In the course of preparing the Condensed Financial Statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events, and, accordingly, actual results could differ from amounts previously established.

The Company's Financial Statements have been prepared on a basis consistent with the accounting principles and policies reflected in the Company's audited financial statements as of and for the year ended December 31, 2009. The year-end Condensed Balance Sheet was derived from audited Financial Statements included in such report, but does not include all disclosures required by GAAP. Certain prior period amounts have been reclassified to properly conform to current period financial statement classification and presentation requirements. We have revised our Condensed Statement of Comprehensive Income (Loss) to reflect the correction of a prior period presentation error. The Company has concluded that the presentation error was immaterial to the previously filed financial statements. See Note 14 to the Condensed Financial Statements.

The Company’s cash management process provides for the daily funding of checks as they are presented to the bank. Included in accounts payable at June 30, 2010 and December 31, 2009 is $17.7 million and $15.7 million, respectively, representing outstanding checks in excess of the bank balance (book overdraft).

2. Bad Debt Allowance

The Company recognized $38.5 million in bad debt expense in the year ended December 31, 2008 related to Flying J, Inc., its wholly owned subsidiary Big West Oil, LLC and its wholly owned subsidiary Big West of California, LLC (BWOC) filing for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code on December 22, 2008. On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., BWOC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. Additionally, on July 6, 2010, the United States Bankruptcy Court approved and confirmed that certain June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of the Company’s claim in Flying J’s pending bankruptcy. Pursuant to the Stipulation, each of the Company and Flying J agreed that the total amount owed to the Company by Flying J was $60.5 million and, as a result, the Company received $60.5 million in cash on July 23, 2010. In the second quarter ended June 30, 2010, the Company recorded a settlement of its Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million. See Notes 12 and 13 to the Condensed Financial Statements.

3. Fair Value Measurements

The authoritative guidance for fair value measurements establishes a three-tier fair value hierarchy, which prioritizes the inputs used to measure fair value. These tiers include: Level 1, defined as unadjusted quoted prices in active markets for identical assets or liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

A financial instrument’s categorization within the fair value hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the classification of assets and liabilities within the fair value hierarchy. The Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) for valuation as a practical expedient for assigning fair value. Oil swaps, natural gas swaps and interest rate swaps are valued using models which are based on active market data and are classified within Level 2 of the fair value hierarchy. Derivatives that are valued based upon models with significant unobservable market inputs (primarily volatility), and that are normally traded less actively are classified within Level 3 of the valuation hierarchy. These models are industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic

measures. The fair value of all derivative instruments are estimated using a combined income and market valuation methodology based upon forward commodity price and volatility curves. The curves are obtained from independent pricing services, and the Company has made no adjustments to the obtained prices. The pricing services publish observable market information from multiple brokers and exchanges. No proprietary models are used by the pricing services for the inputs. All valuations were compared against counterparty valuations to verify the reasonableness of prices. The Company also considers counterparty credit risk and its own credit risk in its determination of all estimated fair values. The Company has consistently applied these valuation techniques in all periods presented and believes it has obtained the most accurate information available for the types of derivative contracts it holds. Level 3 derivatives include oil collars, natural gas collars and natural gas basis swaps. The Company recognizes transfers between levels at the end of the reporting period for which the transfer has occurred.

The following tables set forth by level within the fair value hierarchy the Company’s net derivative assets and liabilities that were measured at fair value on a recurring basis as of June 30, 2010 and December 31, 2009.

Assets and liabilities measured at fair value on a recurring basis

June 30, 2010 (in millions)	Total carrying value on the Condensed Balance Sheet	Level 2	Level 3
Commodity derivatives liability, net	$ (27.8)	$ (23.8)	$ (4.0)
Interest rate derivatives liability, net	(11.2)	(11.2)	—
Total derivative liabilities, net at fair value	$ (39.0)	$ (35.0)	$ (4.0)

December 31, 2009 (in millions)	Total carrying value on the Condensed Balance Sheet	Level 2	Level 3
Commodity derivatives liability, net	$ (88.5)	$ (62.5)	$ (26.0)
Interest rate derivatives liability, net	(8.9)	(8.9)	—
Total derivative liabilities, net at fair value	$ (97.4)	$ (71.4)	$ (26.0)

Changes in Level 3 fair value measurements

The table below includes a rollforward of the Condensed Balance Sheet amounts (including the change in fair value) for financial instruments classified by the Company within Level 3 of the fair value hierarchy. When a determination is made to classify a financial instrument within Level 3 of the fair value hierarchy, the determination is based upon the significance of the unobservable factors to the overall fair value measurement. Level 3 financial instruments typically include, in addition to the unobservable or Level 3 components, observable components (that is, components that are actively quoted and can be validated to external sources).

(in millions)	Three months ended June 30, 2010	2009	Six months ended June 30, 2010	2009
Fair value (liability) asset, beginning of period	$ (34.5)	$ 137.5	$ (26.0)	$ 172.5
Total realized and unrealized gain (loss) included in Realized and unrealized gain (loss) on derivatives	41.2	(31.1)	41.9	6.0
Purchases, sales and settlements, net	(10.7)	(63.3)	(19.9)	(138.8)
Transfers in and/or out of Level 3	—	—	—	3.4
Fair value (liability) asset, end of period	$ (4.0)	$ 43.1	$ (4.0)	$ 43.1
Total unrealized gains (losses) included in income related to financial assets and liabilities still on the Condensed Balance Sheet at June 30, 2010 and 2009	$ 30.5	$ (31.1)	$ 22.0	$ (8.3)

The $3.4 million of transfers out of Level 3 for the six months ended June 30, 2009 represent crude oil collars that were converted to crude oil swaps during the first quarter of 2009.

For further discussion related to the Company's derivatives see Note 4 to the Condensed Financial Statements.

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Berry Petroleum Company
Notes to Condensed Financial Statements

Fair Market Value of Financial Instruments

The Company used various assumptions and methods in estimating the fair values of its financial instruments. The carrying amounts of cash and cash equivalents and accounts receivable approximated their fair value due to the short-term maturity of these instruments. The carrying amount of the Company's credit facilities approximated fair value, because the interest rates on the credit facilities are variable and could be at similar rates today. The fair values of the 8.25% senior subordinated notes due 2016 and the 10.25% senior notes due 2014 were estimated based on quoted market prices. The fair values of the Company's derivative instruments and other investments are discussed above.

(in millions)	As of June 30, 2010 Carrying Amount	Estimated Fair Value
Line of credit	$ 3	$ 3
Senior secured revolving credit facility	310	310
8.25% Senior subordinated notes due 2016	200	194
10.25% Senior notes due 2014	438	481
	$ 951	$ 988

(in millions)	As of December 31, 2009 Carrying Amount	Estimated Fair Value
Senior secured revolving credit facility	$ 372	$ 372
8.25% Senior subordinated notes due 2016	200	196
10.25% Senior notes due 2014	437	487
	$ 1,009	$ 1,055

4. Derivative Instruments

The Company uses financial derivative instruments as part of its price risk management program to achieve a more predictable, economic cash flow from its oil and natural gas production by reducing its exposure to price fluctuations. The Company has entered into financial commodity swap and collar contracts to fix the floor and ceiling prices received for a portion of the Company's oil and natural gas production. The terms of the contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and future financial commitments. The Company periodically enters into interest rate derivative agreements to protect against changes in interest rates on its floating rate debt. For further discussion related to the fair value of the Company's derivatives see Note 3 to the Condensed Financial Statements.

As of June 30, 2010, the Company had the following commodity derivatives:

	2010	2011	2012
Oil Bbl/D:	15,930	12,020	6,000
Natural Gas MMBtu/D:	19,000	15,000	15,000

The Company entered into the following crude oil two-way collars during the six months ended June 30, 2010:

Term	Average Barrels Per Day	Floor/Ceiling Prices
Full year 2010	500	$75.00/$93.95
Full year 2010	500	$75.00/$94.45
Full year 2011	500	$75.00/$100.75
Full year 2011	500	$75.00/$101.15

Full year 2011	1,000	$75.00/$91.25
Full year 2012	500	$75.00/$105.00
Full year 2012	500	$75.00/$106.00
Full year 2012	1,000	$75.00/$95.00

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The Company entered into the following crude oil three-way collars during the six months ended June 30, 2010:

Term	Average Barrels Per Day	Floor/Swap/Ceiling Prices
Full year 2011	1,000	$60.00 / $80.00 / $101.00
Full year 2012	1,000	$60.00 / $80.00 / $120.00

The Company entered into the following natural gas swaps during the six months ended June 30, 2010:

Term	Average MMBtus Per Day	Swap Prices
Full year 2011	5,000	$ 5.50
Full year 2012	5,000	$ 5.75

Discontinuance of cash flow hedge accounting

Prior to January 1, 2010, the Company designated most of its commodity and interest rate derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to Accumulated other comprehensive loss (AOCL). Effective January 1, 2010, the Company elected to de-designate all of its commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009. As a result, subsequent to December 31, 2009, the Company recognizes all gains and losses from changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in AOCL.

At December 31, 2009, AOCL consisted of $97.4 million, ($60.4 million, net of tax) of unrealized losses, representing the change in the fair value of the Company's open commodity and interest rate derivative contracts designated as cash flow hedges as of that balance sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such fair values at December 31, 2009 are frozen in AOCL as of the de-designation date and reclassified into earnings as the original hedge transactions settle. During the three and six months ended June 30, 2010, $6.5 million ($4.0 million, net of tax) and $12.0 million ($7.4 million, net of tax), respectively, of amortization of AOCL relating to de-designated commodity and interest rate hedges were reclassified from AOCL into earnings. As of June 30, 2010, AOCL consisted of $85.4 million ($52.9 million, net of tax) of unrealized losses on commodity and interest rate derivative contracts that had been previously designated as cash flow hedges. The Company expects to reclassify into earnings from AOCL after-tax net losses of $28.2 million related to de-designated commodity and interest rate derivative contracts during the next twelve months.

At June 30, 2010, the net fair value derivative liability was $39.0 million as compared to a net fair value liability of $97.4 million at December 31, 2009 which reflects changes in commodity prices and interest rates. Based on NYMEX strip pricing as of June 30, 2010, the Company expects to make net payments under the existing derivatives of $6.6 million during the next twelve months.

The related cash flow impact of all of the Company's derivatives is reflected in cash flows from operating activities.

The Company presents its derivative assets and liabilities on its Condensed Balance Sheets on a net basis. The Company nets derivative assets and liabilities whenever it has a legally enforceable master netting agreement with a counterparty to a derivative contract. The Company uses these agreements to manage and reduce its potential counterparty credit risk.

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The following table disaggregates the Company's net derivative assets and liabilities into gross components before giving effect to master netting arrangements. Finally, the Company identifies the line items on its Condensed Balance Sheets in which these fair value amounts are included. The gross asset and liability values in the table below are segregated between those derivatives designated in qualifying hedge accounting relationships and those not designated in hedge accounting relationships.

	As of June 30, 2010			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Total derivatives designated as hedging instruments		$ —		$ —

Commodity	Current assets	$ 10.9	Current liability	$ 20.6
Commodity	Long term assets	7.1	Long term liabilities	25.2
Interest rate			Long term assets	0.4
Interest rate			Current assets	3.4
Interest rate			Current liability	3.0
Interest rate			Long term liabilities	4.4
Total derivatives not designated as hedging instruments		$ 18.0		$ 57.0
Total derivatives		$ 18.0		$ 57.0

	As of December 31, 2009			
	Derivative Assets		Derivative Liabilities	
(in millions)	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Commodity	Current assets	$ 15.5	Current liability	$ 30.8
Commodity	Long term assets	0.4	Long term liabilities	74.1
Commodity	Current liability	0.2		
Commodity	Long term liabilities	1.2		
Interest rate	Long term assets	0.3	Current assets	3.5
Interest rate			Current liabilities	2.7
Interest rate			Long term liabilities	3.0
Total derivatives designated as hedging instruments		$ 17.6		$ 114.1
Commodity		$ —	Current assets	$ 0.4
Commodity		—	Current liabilities	0.5
Total derivatives not designated as hedging instruments		$ —		$ 0.9
Total derivatives		$ 17.6		$ 115.0

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Berry Petroleum Company
Notes to Condensed Financial Statements

The tables below summarize the location and the amount of derivative instrument gains (losses) before income taxes reported in the Condensed Statements of Income (Loss) for the periods indicated (in millions):

Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Three months Ended June 30, 2010	Three months Ended June 30, 2009
Commodity			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ —	$ (146.5)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Sales of oil and gas	(4.1)	16.6
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	—	(22.6)
Interest rate			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ —	$ 5.9
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Interest expense	(2.4)	(1.5)
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	—	(0.3)

Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009(1)
Commodity			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ —	$ (138.3)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Sales of oil and gas	(6.9)	79.1
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	—	0.3
Interest rate			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ —	$ 2.1
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Interest expense	(5.1)	(2.5)
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	—	(0.3)

(1) Prior year amounts have been revised. See Note 14 to the Condensed Financial Statements.

Amount of gain or (loss) recognized in income on derivatives not designated as hedging instruments under authoritative guidance for the periods indicated (in millions):

Derivatives not designated as Hedging Instruments under authoritative guidance	Location of Gain (Loss) Recognized in Income	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009
Commodity	Realized and unrealized gain (loss) on derivatives, net	$ 58.8	$ (8.5)
Interest Rates	Realized and unrealized gain (loss) on derivatives, net	(2.7)	—

Derivatives not designated as Hedging Instruments under authoritative guidance	Location of Gain (Loss) Recognized in Income	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Commodity	Realized and unrealized gain (loss) on derivatives, net	$ 63.7	$ (8.3)
Commodity	Loss from discontinued operations, net of taxes	—	(0.5)
Interest Rates	Realized and unrealized gain (loss) on derivatives, net	(6.0)	—

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Credit risk

The Company does not require collateral or other security from counterparties to support derivative instruments. However, the agreements with those counterparties typically contain netting provisions such that if a default occurs, the non-defaulting party can offset the amount payable to the defaulting party under the derivative contract with the amount due from the defaulting party. As a result of the netting provisions the Company's maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. The maximum amount of loss due to credit risk that the Company would have incurred if all counterparties to its derivative contracts failed to perform at June 30, 2010 was $14.2 million. The credit rating of each of the counterparties was AA-/Aa3, or better as of June 30, 2010. As of June 30, 2010, the Company's largest three counterparties accounted for 93% of the value of its total derivative positions.

As of June 30, 2010, the counterparties to the Company's commodity derivative contracts consist of nine financial institutions. The Company's counterparties or their affiliates are generally also lenders under the Company's senior revolving credit facility. As a result, the counterparties to the Company's derivative agreements share in the collateral supporting the Company's senior revolving credit facility. The Company is not generally required to post additional collateral under derivative agreements.

Certain of the Company's derivative agreements contain provisions that require cross defaults and acceleration of those instruments to any material debt. If the Company was to default on any of its material debt agreements, it would be a violation of these provisions, and the counterparties to the derivative instruments could request immediate payment on derivative instruments that are in a net liability position at that time. As of June 30, 2010, the Company was in a net liability position with six of the counterparties to the Company's derivative instruments, totaling $53.2 million.

5. Shareholder's Equity

In January 2010, the Company issued 8,000,000 shares of Class A Common Stock at a price of $29.25 per share. Net proceeds from this offering were $224.3 million after deducting underwriting discounts and commissions and offering expenses. The Company used the net proceeds from the offering to fund the purchase of the March Acquisition (as defined below) and to repay a portion of the outstanding borrowings under the senior secured revolving credit facility. See Note 6 to the Condensed Financial Statements.

6. Acquisitions and Divestitures

In March 2010, the Company acquired interests in producing properties principally on 6,900 net acres in the Permian basin of West Texas (W. Texas) for $133 million, comprised of an initial purchase price of $126 million, and customary post-closing adjustments of approximately $7 million (the March Acquisition). The March Acquisition was financed with the proceeds from the issuance of the Company's common stock in January of 2010. In April 2010, the Company closed on the acquisition of an additional 3,200 net acres in the Permian basin for approximately $14 million, including normal post closing adjustments (the April Acquisition and, together with the March Acquisition, the Permian Basin Acquisitions). The Permian Basin Acquisitions included properties with total proved reserves of approximately 13 MMBOE, of which 83% were crude oil and 21% were proved developed.

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The Permian Basin Acquisitions qualify as business combinations and, as such, the Company estimated the fair value of each property as of the acquisition date (the date on which the Company obtained control of the properties). The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs.

The following table summarizes the consideration paid to the seller and the amounts of the assets acquired and liabilities assumed in the March Acquisition. The purchase price allocation is preliminary and subject to customary adjustments.

	(In thousands)

Consideration paid to seller:		
Cash consideration	$	133,313
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed and undeveloped properties		134,559
Fair value of derivatives		316
Asset retirement obligation		(1,367)
Other liabilities assumed		(195)
Total identifiable net assets	$	133,313

The March Acquisition had an effective date of January 1, 2010, and activity from January 1, 2010 through March 4, 2010 was treated as purchase price adjustments. The preliminary purchase price allocation included an estimate for activity between January 1, 2010 and March 4, 2010; however, actual amounts were greater than the Company's estimate which resulted in an increase to the total cash consideration paid to the seller. As a result, the initial $1.4 million of Gain on purchase of oil and natural gas properties recorded in the first quarter of 2010 has been reversed in the second quarter of 2010 to reflect the purchase price adjustments.

The following table summarizes the consideration paid to the seller and the amounts of the assets acquired and liabilities assumed in the April Acquisition. The preliminary purchase price allocation is subject to customary adjustments and includes $1.6 million that remains in escrow pending the resolution of certain obligations of the seller that have not yet been satisfied.

	(In thousands)	
Consideration paid to seller:		
Cash consideration	$	14,250
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Proved developed and undeveloped properties		16,192
Asset retirement obligation		(1,942)
Total identifiable net assets	$	14,250

Acquisition costs of $0.5 million and $2.6 million have been recorded in the Condensed Statements of Income (Loss) under the caption Transaction costs on acquisitions in the three and six months ended June 30, 2010, respectively. Revenues of $6.6 million and $8.7 million generated by the acquired properties have been included in the accompanying Condensed Statements of Income (Loss) in the three and six months ended June 30, 2010, respectively. Earnings of $1.1 million and $1.6 million generated by the Permian Basin Aquisitions have been included in the accompanying Condensed Statements of Income (Loss) in the three and six months ended June 30, 2010, respectively.

Divestitures

On March 3, 2009, the Company entered into an agreement to sell its DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of the assets was April 1, 2009. The Company recorded a pre-tax impairment loss of $9.6 million related to the sale, which is reflected within the $7.0 million Loss from discontinued operations, net of taxes, on its Condensed Statement of Income (Loss) for the six months ended June 30, 2009.

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Loss from discontinued operations, net of taxes, on the accompanying Condensed Statements of Income (Loss) is comprised of the following (in thousands):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2010		2009		2010		2009	
Total revenues	$	—	$	(330)	$	—	$	5,689
Total expenses		—		—		—		16,283
Loss from discontinued operations, before income taxes		—		(330)		—		(10,594)
Income tax benefit		—		118		—		3,603
Loss from discontinued operations, net of taxes	$	—	$	(212)	$	—	$	(6,991)

7. Dry hole, abandonment, impairment and exploration

During the three and six months ended June 30, 2010, the Company incurred dry hole, abandonment, impairment and exploration expense of $0.3 million and $1.6 million, respectively, which was primarily a result of mechanical failure encountered on one well in the Piceance basin. The well was abandoned in favor of drilling a replacement well from the same well pad. During the three months ended June 30, 2009, the Company did not incur any dry hole, abandonment, impairment and exploration expense. During the six months ended June 30, 2009 the Company had dry hole, abandonment, impairment and exploration charges of $0.1 million.

8. Asset Retirement Obligation (ARO)

The following table summarizes the change in the ARO for the six months ended June 30 (in thousands):

	2010	2009
Beginning balance at January 1	$ 43,487	$ 41,967
Liabilities incurred	1,860	—
Liabilities settled	(1,534)	(175)
Liabilities assumed	3,309	—
Disposition of assets	—	(2,752)
Accretion expense	2,191	1,946
Ending balance at June 30	$ 49,313	$ 40,986

The ARO reflects the estimated present value of the amount of dismantlement, removal, site reclamation and similar activities associated with the Company's oil and gas properties. Inherent in the fair value calculation of the ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the oil and gas property balance.

9. Debt Obligations

Short-term line of credit

Borrowings under the Company's senior secured money market line of credit (the Secured Line of Credit) may be up to $30 million for a maximum of 30 days. The Secured Line of Credit may be terminated at any time upon written notice by either the Company or the lender.

There was $3.3 million outstanding on the Secured Line of Credit at June 30, 2010 and no outstanding borrowings at December 31, 2009. Interest on amounts borrowed is charged at LIBOR plus a margin of approximately 1.4%. The weighted average interest rate on outstanding borrowings on the Secured Line of Credit at June 30, 2010 and December 31, 2009 was 1.8% and 0%, respectively.

Senior secured revolving credit facility

The Company's senior secured revolving credit facility (the Agreement) has a current borrowing base and lender commitments of $938 million. The LIBOR and prime rate margins are between 2.25% and 3.0% based on the ratio of credit outstanding to the borrowing base and the annual commitment fee on the unused portion of the credit facility is 0.50%.

Covenants under the Agreement are as follows:

Total funded debt to EBITDAX (1) ratio not greater than:		Senior secured debt to EBITDAX ratio not greater than:			
2010	Thereafter	to Sep 2010	Mar 2011	Sep 2011	Thereafter
4.50	4.00	3.75	3.50	3.25	3.0

(1) Net income before interest expense, income tax expense, depreciation and amortization expense, exploration expense and non-cash items of income.

The Agreement also contains a current ratio covenant which, as defined, must be at least 1.0. The total outstanding debt at June 30, 2010 under the Agreement, as amended, and the Secured Line of Credit was $310 million and $3 million, respectively, and $24 million in letters of credit have been issued under the facility, leaving $601 million in borrowing capacity available under the Agreement. The maximum amount available is subject to semi-annual redeterminations of the borrowing base, based on the value of the Company's proved oil and gas reserves, in April and October of each year in accordance with the lenders' customary procedures and practices. Both the Company and the banks have the bilateral right to one additional redetermination each year. The Company's borrowing base of $938 million was reconfirmed in April 2010.

10.25% senior notes due 2014

On May 27, 2009, the Company issued in a public offering $325 million principal amount of 10.25% senior notes due 2014 ($325 million Notes). Interest on the $325 million Notes is paid semi-annually in June and December of each year. The $325 million Notes were issued at a discount to par value of 93.546%, and are carried on the Condensed Balance Sheet at their amortized cost. The deferred costs of approximately $9.5 million associated with the issuance of this debt are being amortized over the five year life of the $325 million Notes.

On August 13, 2009, the Company issued in a public offering an additional $125 million principal amount of its 10.25% senior notes due 2014 ($125 million Notes and, together with the $325 million Notes, the Notes). The $125 million Notes were issued at a premium to par value of 104.75%, and are carried on the Condensed Balance Sheet at their amortized cost. The deferred costs of approximately $1.9 million associated with the issuance of this debt are being amortized over the five year life of the $125 million Notes.

The $125 million Notes and the $325 million Notes are treated as a single series of debt securities and are carried on the Condensed Balance Sheet at their combined amortized cost.

8.25% senior subordinated notes due 2016

In 2006, the Company issued in a public offering $200 million of 8.25% senior subordinated notes due 2016 (the Sub notes). Interest on the Sub notes is paid semiannually in May and November of each year. The deferred costs of approximately $5.2 million associated with the issuance of this debt are being amortized over the ten year life of the Sub notes.

Financial Covenants

The Agreement contains restrictive covenants as described above. Under the Company's Notes and Sub notes as long as the interest coverage ratio (as defined) is greater than 2.5 times, the Company may incur additional debt. The Company was in compliance with all of these covenants as of June 30, 2010.

	As of June 30, 2010
Current Ratio (Not less than 1.0)	6.0
Total Funded Debt Ratio to EBITDAX (Not greater than 4.50)	2.8
Interest Coverage Ratio (Not less than 2.5)	4.1
Senior Secured Debt Ratio to EBITDAX (Not greater than 3.75)	0.9

The weighted average interest rate on the Company's total outstanding borrowings was 7.3% and 7.0% at June 30, 2010 and December 31, 2009, respectively.

10. Income Taxes

The effective income tax rate for the three months ended June 30, 2010 and 2009 was 38.1% and 36.1%, respectively. The effective income tax rate was 37.9% and 33.0% for the six months ended June 30, 2010 and 2009, respectively. The increase in rate is primarily due to a one-time reduction in state deferred rates and uncertain tax positions in the prior periods. Reductions in the rate during the prior periods were the result of acquisitions in more tax favorable jurisdictions that reduced future state tax obligations, as well as favorable state tax incentives. The Company's estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences.

As of June 30, 2010, the Company had a gross liability for uncertain tax benefits of $5.3 million all of which, if recognized, would affect the effective tax rate. Gross uncertain tax positions were reduced due to new evaluations of tax positions claimed. There were no significant changes to the calculation since December 31, 2009. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits in income tax expense, which is consistent with the recognition of these items in prior reporting periods. The Company had accrued approximately $0.7 million of interest related to its uncertain tax positions as of both June 30, 2010 and December 31, 2009.

11. Earnings per Share

Basic net income per common share is calculated by dividing adjusted net income available to common shareholders by the weighted average number of common shares outstanding during each period. Diluted net income per common share is calculated by dividing adjusted net income by the weighted average number of diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the diluted earnings per share calculations consist of unvested restricted stock awards and outstanding stock options using the treasury method. When a loss exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share accordingly.

The two-class method of computing earnings per share is required for those entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Restricted stock issued prior to January 1, 2010 under the Company's stock incentive plans has the right to receive non-forfeitable dividends, participating on an equal basis with common stock. Restricted stock issued subsequent to January 1, 2010 under the Company's stock incentive plans no longer has the right to receive non-forfeitable dividends. Therefore, unvested restricted stock issued prior to January 1, 2010 must be allocated to both common stock and these participating securities under the two-class method. Stock units issued to directors under the Company's nonemployee directors deferred compensation plan also have the right to be credited with non-forfeitable dividends, participating on an equal basis with common stock. Stock options issued under the Company's stock incentive plans do not participate in dividends.

The following table shows the computation of basic and diluted net income (loss) per share from continuing and discontinued operations for the three and six months ended June 30, 2010 and 2009 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income (loss) from continuing operations	$ 89,023	$ (12,768)	$ 106,692	$ 29,010
Less: Income allocable to participating securities	1,713	—	2,133	712
Income (loss) available for shareholders	$ 87,310	$ (12,768)	$ 104,559	$ 28,298
Net loss from discontinued operations	$ —	$ (212)	$ —	$ (6,991)
Less: Income allocable to participating securities	—	—	—	—
Loss from discontinued operations available for shareholders	$ —	$ (212)	$ —	$ (6,991)

Basic earnings (loss) per share from continuing operations	$ 1.65	$ (0.28)	$ 2.01	$ 0.63
Basic loss per share from discontinued operations	—	—	—	(0.15)
Basic earnings (loss) per share	$ 1.65	$ (0.28)	$ 2.01	$ 0.48
Diluted earnings (loss) per share from continuing operations	$ 1.64	$ (0.28)	$ 2.00	$ 0.63
Diluted loss per share from discontinued operations	—	—	—	(0.15)
Diluted earnings (loss) per share	$ 1.64	$ (0.28)	2.00	$ 0.48
Weighted average shares outstanding - basic	52,965	44,606	52,027	44,594
Add: Dilutive effects of stock options and RSUs	448	206	380	126
Weighted average shares outstanding - dilutive	53,413	44,812	52,407	44,720

Options to purchase 0.8 million and 1.2 million shares were not included in the diluted earnings per share calculation for the three and six months ended June 30, 2010, respectively, because their effect would have been anti-dilutive. Options to purchase 1.7 million and 1.9 million shares were not included in the diluted earnings (loss) per share calculation for the three and six months ended June 30, 2009, respectively, because their effect would have been anti-dilutive.

12. Commitments and Contingencies

The Company's contractual obligations not included in its Condensed Balance Sheet as of June 30, 2010 (except Long-term debt and Asset retirement obligations) are as follows (in millions):

	Total	2010	2011	2012	2013	2014	Thereafter
Long-term debt and interest	$ 1,264.6	$ 38.6	$ 70.5	$ 376.9	$ 62.6	$ 485.7	$ 230.3
Asset retirement obligation	49.3	1.0	2.9	2.8	2.8	2.9	36.9
Operating lease obligations	15.3	1.2	2.6	2.6	2.6	2.6	3.7
Drilling and rig obligations	31.5	6.0	25.5	—	—	—	—
Firm natural gas transportation contracts	126.7	9.9	19.7	17.6	15.7	14.8	49.0
Total	$ 1,487.4	$ 56.7	$ 121.2	$ 399.9	$ 83.7	$ 506.0	$ 319.9

Operating leases

The Company leases corporate and field offices in California, Colorado and Texas. Rent expense with respect to its lease commitments was $0.6 million for both the three months ended June 30, 2010 and 2009 and was $1.1 million for both the six months ended June 30, 2010 and 2009.

In 2006, the Company purchased a corporate aircraft which was subsequently sold and contracted under a ten year operating lease beginning December 2006.

Drilling obligations

Included in the table above are the Company's contractual obligations on its Piceance assets in Colorado. As of June 30, 2010, the Company must spud additional wells of its original 120 wells commitment by February 2011 to avoid penalties of $0.2 million per well. The Company's satisfying this commitment and further developing these assets depends on Piceance infrastructure and access, drilling resources, including capital availability, and other factors, all of which will be further evaluated throughout the remainder of 2010.

Firm natural gas transportation

In July 2009, the Company closed on the financing of its E. Texas gas gathering system for $18.4 million in cash. The Company entered into concurrent long-term gas gathering agreements for the E. Texas production which contained an embedded lease. There is no minimum payment required under these agreements. For the three months ended June 30, 2010 and 2009, the Company incurred $1.5 and $0, respectively, under the agreements. For the six months ended June 30, 2010 and 2009, the Company incurred $2.6 million and $0, respectively, under the agreements.

In June 2009, the Company amended its natural gas firm transportation agreement providing for transportation of its gas from Tex-OK to Orange County, Florida (Zone 1). The agreement provides for minimum volume of 25,000 MMBtu/d and a maximum volume of 55,000 MMBtu/D.

The Company has long-term firm transportation contracts that total 35,000 MMBtu/D on the Rockies Express (REX) pipeline for gas production in the Piceance basin. The Company pays a demand charge for this capacity and its own production did not completely fill that capacity. To maximize the utilization of its firm transportation, the Company bought its partners' share of the gas produced in the Piceance basin at the market rate for that area and used its excess transportation to move this gas to the sales point. The pre-tax net of its gas marketing revenue and its gas marketing expense in the Condensed Statements of Income (Loss) is $0.6 million for both the three months ended June 30, 2010 and 2009. The pre-tax net of its gas marketing revenue and its gas marketing expense in the Condensed Statements of Income (Loss) is $1.1 million and $0.9 million for the six months ended June 30, 2010 and 2009, respectively.

Berry has signed firm transportation service agreements with El Paso Corporation for an average total of 35,000 MMBtu/D of firm transportation on the proposed Ruby Pipeline from Opal, WY to Malin, OR. The expectation is that the project will proceed and be in service in 2011.

Other commitments

The Company is a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of a minimum of 5,000 Bbl/D of its Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for the Company's 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for the Company's crude oil. Gross oil production from the Company's Uinta properties averaged approximately 2,720 Bbl/D in the first six months of 2010.

In December 2008, Flying J, Inc., its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed the Company that it was unable to receive the Company's California production. Included in the allowance for doubtful accounts is $38.5 million due from BWOC. Of the $38.5 million due from BWOC, $11.8 million represents 20 days of the Company's December 2008 crude oil sales, an administrative claim under the bankruptcy proceedings, and $26.7 million represents November 2008 and the balance of December 2008 crude oil sales which would have the same priority as other general unsecured claims. The Company has settled its claim in the Flying J bankruptcy and received a payment of $60.5 million on July 23, 2010. See Note 13 to the Condensed Financial Statements.

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The Company has no material accrued environmental liabilities for its sites, including sites in which governmental agencies have designated the Company as a potentially responsible party, because it is not probable that a loss will be incurred and the minimum cost and/or amount of loss cannot be reasonably estimated. However, because of the uncertainties associated with environmental assessment and remediation activities, future expense to remediate the currently identified sites, and sites identified in the future, if any, could be incurred. Management believes, based upon current site assessments, that the ultimate resolution of any matters will not result in substantial costs incurred. The Company is involved in various other lawsuits, claims and inquiries, most of which are routine to the nature of its business. In the opinion of management, the resolution of these matters will not have a material effect on its financial position, results of operations or liquidity.

Certain of the Company's royalty payment calculations are being disputed. The Company believes that its royalty calculations are in accordance with applicable leases and other agreements. However, the disputed amounts that the Company may be required to pay are up to approximately $6 million.

In July 2009, the Company received a notice of proposed civil penalty from the Bureau of Land Management (BLM) related to the Company's alleged non-compliance during 2007 with regulations relating to the operation and position of certain valves in its Uinta basin operations. The proposed civil penalty was $69.6 million and reflects the theoretical maximum penalty amount under applicable regulations, absent mitigating factors. In 2007 the Company immediately remediated the instances of non-compliance, cooperated fully with the BLM's investigation and the Company believes no production was lost, all royalties were paid and there was no harm to the environment. Due to the above mitigating factors, among others, the Company believes this matter will be resolved by the payment of a penalty that will not exceed $2.1 million and accrued such amount in the second quarter of 2009.

During the California energy crisis in 2000 and 2001, the Company had electricity sales contracts with various utilities and a portion of the electricity prices paid to the Company under such contracts from December 2000 to March 27, 2001 has been under a degree of legal challenge since that time. It is possible that the Company may have a liability pending the final outcome of the California Public Utilities Commission (CPUC) proceedings on the matter. There are ongoing proceedings before the CPUC in which Edison and PG&E are seeking credit against future payments they are to make for electricity purchases based on retroactive adjustments to pricing under contracts with the Company. Whether or not retroactive adjustments will be ordered, how such adjustments would be calculated and what period they would cover are too uncertain to estimate at this time.

13. Subsequent Events

On July 6, 2010, the Joint Plan of Reorganization of Flying J, Inc., BWOC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. In addition, the United States Bankruptcy Court approved and confirmed that certain June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of the Company's claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, each of the Company and Flying J agreed that the total amount owed to the Company by Flying J arising out of Flying J's voluntary bankruptcy filed December 22, 2008 was $60.5 million and, as a result, the Company received $60.5 million in cash on July 23, 2010. In the second quarter ended June 30, 2010 the Company recorded a settlement of its Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million.

14. Correction of Other Comprehensive Income (Loss)

The Company noted a presentation error in the Statements of Comprehensive Income (Loss) and the related disclosures in Note 3 to the audited financial statements contained in the Company's Annual Report on Form 10-K for the year ended December 31, 2009. The Company has concluded that the presentation error was immaterial to the audited financial statements contained in the 2009 Form 10-K. The effects of the presentation errors are summarized in the tables below:

The components of comprehensive income (loss):

	For the twelve months December 31, 2009	
	As Previously Reported	As Revised
Net Income	$ 54,030	$ 54,030
Unrealized gains (losses) on derivatives, net of income taxes	205,318	(129,287)
Reclassification of realized (gains) losses, net of income taxes	(31,249)	(44,782)
Comprehensive income (loss)	$ 228,099	$ (120,039)

The table below summarizes the impacts of the Company's derivative instruments gains (losses) before income taxes reported in the Statements of Income (Loss) for the twelve months ended December 31, 2009:

Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Twelve Months Ended December 31, 2009 Previously Reported	Twelve Months Ended December 31, 2009 As Adjusted
Commodity			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ (240.9)	$ (206.4)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Sales of oil and gas	65.0	79.3
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	13.7	(0.6)
Interest rate			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ 8.8	$ (2.7)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Interest expense	(7.0)	(7.0)
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	—	—

The Company also noted that the presentation error existed in the quarterly filings for the periods ended March 31, 2009, June 30, 2009, September 30, 2009 and March 31, 2010 and the related disclosures in Note 4 for the periods ended March 31, 2009, June 30, 2009 and September 30, 2009. The Company concluded that the presentation error was immaterial to the previously filed financial statements. The effects of the presentation errors are summarized in the tables below:

The components of comprehensive income (loss):

	For the Three Months Ended March 31, 2009 As Previously Reported	For the Three Months Ended March 31, 2009 As Revised
Net Income	$ 34,998	$ 34,998
Unrealized gains (losses) on derivatives, net of income taxes	78,577	(11,417)
Reclassification of realized (gains) losses, net of income taxes	(29,022)	(38,138)
Comprehensive income (loss)	$ 84,553	$ (14,557)

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Notes to Condensed Financial Statements

The table below summarizes the impacts of the Company's derivative instruments gains (losses) before income taxes reported in the Statements of Income (Loss) for the three months ended March 31, 2009:

Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Three Months Ended March 31, 2009 Previously Reported	Three Months Ended March 31, 2009 As Adjusted
Commodity			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ 45.4	$ 8.3
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Sales of oil and gas	48.2	62.5
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	22.7	22.8
Interest rate			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ (3.4)	$ (3.8)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Interest expense	(1.0)	(1.0)
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	—	—

The components of comprehensive income (loss):

	For the Three Months Ended June 30, 2009 As Previously Reported	For the Three Months Ended June 30, 2009 As Revised	For the Six Months Ended June 30, 2009 As Previously Reported	For the Six Months Ended June 30, 2009 As Revised
Net (Loss) Income	$ (12,980)	$ (12,980)	$ 22,019	$ 22,019
Unrealized gains (losses) on derivatives, net of	91,952	(73,055)	170,529	(84,472)

income taxes				
Reclassification of realized (gains) losses, net of income taxes	(9,583)	(9,314)	(38,605)	(47,452)
Comprehensive income (loss)	$ 69,389	$ (95,349)	$ 153,943	$ (109,905)

The table below summarizes the impacts of the Company's derivative instruments gains (losses) before income taxes reported in the Statements of Income (Loss) for the six months ended June 30, 2009:

Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Six Months Ended June 30, 2009 Previously Reported	As Adjusted
Commodity			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ 175.2	$ (138.3)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Sales of oil and gas	40.2	79.1
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	14.6	0.3
Interest rate			
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ (4.6)	$ 2.1
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Interest expense	(1.6)	(2.5)
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	(0.3)	(0.3)

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The components of comprehensive income (loss):

	For the Three Months Ended September 30, 2009 As Previously Reported	As Revised	For the Nine Months Ended September 30, 2009 As Previously Reported	As Revised
Net income	$ 19,007	$ 19,007	$ 41,026	$ 41,026
Unrealized gains (losses) on derivatives, net of income taxes	(563)	3,306	169,966	(81,166)
Reclassification of realized (gains) losses, net of income taxes	(454)	(2,289)	(39,059)	(49,741)
Comprehensive income (loss)	$ 17,990	$ 20,024	$ 171,933	$ (89,881)

The table below summarizes the impacts of the Company's derivative instruments gains (losses) before income taxes reported in the Statements of Income (Loss) for the three and nine months ended September 30, 2009:

Derivatives cash flow hedging relationships	Location of Gain (Loss) Recognized in Income	Three Months Ended September 30, 2009 Previously Reported	As Adjusted	Nine Months Ended September 30, 2009 Previously Reported	As Adjusted
Commodity					
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ (0.7)	$ 9.3	$ 174.5	$ (128.9)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Sales of oil and gas	1.6	5.6	41.8	84.7
Gain (Loss) Recognized in Income (Ineffective portion)	Realized and unrealized gain (loss) on derivatives, net	(0.6)	(0.6)	14.0	(0.2)
Interest rate					
Gain (Loss) Recognized in AOCL (Effective Portion)	Accumulated other comprehensive income (loss)	$ 0.7	$ (4.5)	$ (3.9)	$ (2.4)
Gain (Loss) Reclassified from AOCL into Income (Effective Portion)	Interest expense	(1.1)	(1.9)	(2.7)	(4.4)
Gain (Loss) Recognized in Income (Ineffective Portion)	Realized and unrealized gain (loss) on derivatives, net	0.1	0.1	(0.2)	(0.2)

The components of comprehensive income (loss):

	For the Three Months Ended March 31, 2010 As Previously Reported	As Revised
Net Income	$ 17,669	$ 17,669
Unrealized gains (losses) on derivatives, net of income taxes	—	
Accumulated other comprehensive loss amortization of de-designated	(3,400)	3,400

hedges, net of income taxes		
Comprehensive income (loss)	$ 14,269	$ 21,069

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Berry Petroleum Company
Management's Discussion and Analysis of Financial Condition and Results of Operations

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected aspects of our financial position and the results of operations during the periods included in the accompanying Condensed Financial Statements. You should read this in conjunction with the discussion under "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the audited Financial Statements for the year ended December 31, 2009 included in our Annual Report on Form 10-K and the Condensed Financial Statements included elsewhere herein.

The profitability of our operations in any particular accounting period will be directly related to the realized prices of oil, gas and electricity sold, the type and volume of oil and gas produced and electricity generated and the results of development, exploitation, acquisition, exploration and hedging activities. The realized prices for natural gas and electricity will fluctuate from one period to another due to regional market conditions and other factors, while oil prices will be predominantly influenced by global supply and demand. The aggregate amount of oil and gas produced may fluctuate based on the success of development and exploitation of oil and gas reserves pursuant to current reservoir management. We benefit from lower natural gas prices as we are a consumer of natural gas in our California operations. In the Rocky Mountains and E. Texas we benefit from higher natural gas pricing. The cost of natural gas used in our steaming operations and electrical generation, production rates, labor, equipment costs, maintenance expenses, and production taxes are expected to be the principal influences on operating costs. Accordingly, our results of operations may fluctuate from period to period based on the foregoing principal factors, among others.

In the second quarter of 2010, diatomite production decreased 836 BOE/D compared to the first quarter of 2010. The decline is primarily due to the inability to drill new wells as we await permits and certain operational changes that we have implemented to facilitate higher production volumes when development drilling resumes. There is no update on when we will be able to resume drilling new wells in the diatomite. Currently the Division of Oil, Gas and Geothermal Resources (DOGGR) is working towards adoption of new regulations for the development of diatomite, which is estimated to take six to twelve months to complete. However, we are currently working with the DOGGR on an interim solution that would allow diatomite development to resume in the last half of 2010. The operational changes that we made during the first half of 2010 should allow us to drill with multiple rigs, accelerate development and significantly improve efficiency when the new permits are issued. In the interim we have reallocated drilling capital from the diatomite project to the Permian, adding a second rig in mid July, and plan to add a third rig in August, expanding our drilling program to approximately 37 wells in the Permian.

Notable Second Quarter Items.
- Achieved production averaging 32,854 BOE/D, comprised of 67% crude oil, up 12% from the first quarter of 2010
- Generated discretionary cash flow [(1)] of $142 million, comprised of $81 million from operations and a $61 million recovery from our claim in the Flying J bankruptcy
- DOGGR in California determined new regulations are needed for the cyclic injection of steam in the diatomite
- While diatomite production was down 836 BOE/D, production from Berry's other California assets increased 565 BOE/D compared to the first quarter of 2010
- Completed three horizontal Haynesville wells with a 30-day average production of 9 to 10 MMcf/D per well
- Established operations in the Permian basin with production of 1,033 BOE/D, in line with expectations
- Closed on the acquisition of an additional 3,200 acres in the Permian basin for $14 million
- Settled our claim in the Flying J bankruptcy and received payment of $60.5 million on July 23, 2010

Notable Items and Expectations for the Third Quarter and Full Year 2010.
- Anticipating 2010 average production between 32,250 and 33,000 BOE/D, an 8% to 10% increase over 2009
- Working with the DOGGR on an interim solution that would allow diatomite development to resume in the last half of 2010
- Planning to run a three rig drilling program in the Permian basin in the third quarter of 2010
- Expecting 2010 development capital expenditures of up to $290 million to be fully funded from operating cash flow

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[(1)] Discretionary cash flow is considered a non-GAAP performance measure and reference should be made to *"Reconciliation of Non-GAAP Measures"* at the end of this Item 2 for further explanation of this performance measure, as well as a reconciliation to the most directly comparable GAAP measure.

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Results of Operations

In the second quarter of 2010, we reported net income from continuing operations of $89.0 million, or $1.64 per diluted share, and net cash flows from operations of $71.4 million. Net income from continuing operations includes a $30.0 million gain on derivatives as a result of non-cash changes in fair values and amortization of frozen fair values and a $37.4 million Flying J settlement, offset by $1.2 million of purchase price adjustments related to the March Acquisition, as defined below.

During the first six months of 2010, we reported net income from continuing operations of $106.7 million, or $2.00 per diluted share, and net cash flows from operations was $134.9 million. Net income from continuing operations includes a $29.2 million gain on derivatives as result of non-cash changes in fair values and amortization of frozen fair values and a $37.5 million Flying J settlement, offset by $0.8 million of dry hole costs and $1.6 million of transaction related costs related to the acquisition of certain properties in the Permian basin, as discussed below.

Acquisitions.

Permian Basin Acquisitions. In March 2010, we acquired interests in producing properties principally on 6,900 net acres in the Permian basin of West Texas (W. Texas) from a private seller for approximately $133 million, including normal post closing adjustments (the March Acquisition). In April 2010 we closed on the acquisition of an additional 3,200 acres in the Permian basin for approximately $14 million, including normal post closing adjustments (the April Acquisition and, together with the March Acquisition, the Permian Basin Acquisitions). The Permian Basin Acquisitions included properties with total proved reserves of approximately 13 MMBOE, of which 83% were crude oil and 21% were proved developed. We now have a drilling inventory of over 200 locations on forty-acre spacing in the Wolfberry trend targeting the Spraberry Dean, Wolfcamp and Strawn formations.

Revenues.

Approximately 73% of our revenues are generated through the sale of oil and natural gas production under either negotiated contracts or spot gas purchase contracts at market prices. Approximately 4% of our revenues are derived from electricity sales from cogeneration facilities which supply approximately 28% of our steam requirement for use in our California thermal heavy oil operations. We have invested in these facilities for the purpose of lowering our steam costs, which are significant in the production of heavy crude oil. Approximately 3% of our revenues are derived from gas marketing sales which represent our excess capacity on the Rockies Express pipeline which we used to market natural gas purchased from our working interest partners.

The following results from continuing operations are in millions (except per share data) for the three and six month periods ended:

	Three months ended,			Six months ended,	
	June 30, 2010	June 30, 2009	March 31, 2010	June 30, 2010	June 30, 2009
Sales of oil	$ 125	$ 103	$ 122	$ 246	$ 201
Sales of gas	27	16	26	53	46
Total sales of oil and gas	$ 152	$ 119	$ 148	$ 299	$ 247
Sales of electricity	8	6	10	18	17
Gas marketing	5	5	8	13	12
Realized and unrealized gain (loss) on derivatives, net	56	(31)	2	58	6
Settlement on Flying J bankruptcy claim	22	—	—	22	—
Interest and other income, net	1	1	—	2	1
Total revenues and other income	$ 244	$ 100	$ 168	$ 412	$ 283
Net income (loss) from continuing operations	$ 89	$ (13)	$ 18	$ 107	$ 29
Diluted earnings (loss) per share from continuing operations	$ 1.64	$ (0.28)	$ 0.34	$ 2.00	$ 0.63

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Operating data. The following table is for the three months ended:

	June 30, 2010	%	June 30, 2009	%	March 31, 2010	%
Heavy oil production (Bbl/D)	17,492	54	16,822	57	17,752	61
Light oil production (Bbl/D)	4,377	13	3,085	11	2,754	9
Total oil production (Bbl/D)	21,869	67	19,907	68	20,506	70
Natural gas production (Mcf/D)	65,909	33	56,174	32	53,309	30
Total (BOE/D)	32,854	100	29,270	100	29,391	100
Oil and gas BOE for continuing operations:						
Average realized sales price	$ 50.81		$ 45.74		$ 55.99	
Average sales price including cash derivative settlements	53.11		45.74		57.09	
Oil, per Bbl for continuing operations:						
Average WTI price	$ 78.05		$ 59.79		$ 78.88	
Price sensitive royalties	(2.90)		(2.08)		(3.04)	
Quality differential and other	(9.71)		(7.86)		(8.12)	
Crude oil derivatives non cash amortization (a)	(2.42)		—		(1.72)	
Crude oil derivatives cash settlements (b)	—		8.91		—	
Oil revenue	$ 63.02		$ 58.76		$ 66.00	
Add: Crude oil derivatives non cash amortization	2.42		—		1.72	
Crude oil derivative cash settlements (c)	0.01		—		(0.22)	
Average realized oil price	$ 65.45		$ 58.76		$ 67.50	
Natural gas price for continuing operations:						
Average Henry Hub price per MMBtu	$ 4.09		$ 3.51		$ 5.30	
Conversion to Mcf	0.20		0.18		0.27	
Natural gas derivatives non cash amortization (a)	0.12		—		0.07	
Natural gas derivative cash settlements (b)	—		0.21		—	
Location, quality differentials and other	0.02		(0.72)		(0.15)	
Natural gas revenue per Mcf	$ 4.43		$ 3.18		$ 5.49	
Less: Natural gas derivatives non cash amortization	(0.12)		—		(0.07)	
Natural gas derivative cash settlements (c)	0.46		—		0.11	

Average realized natural gas price per Mcf	$ 4.77	$ 3.18	$ 5.53

(a) *Includes non-cash amortization of frozen December 31, 2009 fair values resulting from January 1, 2010 discontinuing of hedge accounting, recorded in Oil and natural gas sales*
(b) *Includes cash settlements on derivatives prior to January 1, 2010, for which we had elected hedge accounting, recorded in Oil and natural gas sales*
(c) *Includes cash settlements on derivatives subsequent to January 1, 2010, for which we had discontinued hedge accounting, recorded in Realized and unrealized gain (loss) on derivatives, net*

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The following table is for the six months ended:

	June 30, 2010	%	June 30, 2009	%
Heavy oil production (Bbl/D)	17,621	57	16,646	53
Light oil production (Bbl/D)	3,570	11	3,076	10
Total oil production (Bbl/D)	21,191	68	19,722	63
Natural gas production (Mcf/D)	59,644	32	69,502	37
Total operations (BOE/D)	31,132	100	31,305	100
DJ Basin Production (BOE/D)	—		1,542	
Production - Continuing Operations (BOE/D)	31,132		29,763	
Oil and gas BOE for continuing operations:				
Average realized sales price	$ 53.24		$ 46.44	
Average sales price including cash derivative settlements	54.98		46.44	
Oil, per Bbl, for continuing operations:				
Average WTI price	$ 78.46		$ 51.58	
Price sensitive royalties	(2.97)		(1.55)	
Quality differential and other	(8.95)		(8.77)	
Crude oil derivatives non cash amortization (a)	(2.08)		—	
Crude oil derivative cash settlements (b)	—		16.36	
Oil Revenue	$ 64.46		$ 57.62	
Add: Crude oil derivatives non cash amortization	2.08		—	
Crude oil derivative cash settlements (c)	(0.10)		—	
Average realized oil price	$ 66.44		$ 57.62	
Natural gas price for continuing operations:				
Average Henry Hub price per MMBtu	$ 4.70		$ 4.21	
Conversion to Mcf	0.24		0.21	
Natural gas derivatives non cash amortization (a)	0.10		—	
Natural gas derivative cash settlements (b)	—		0.70	
Location, quality differentials and other	(0.13)		(0.96)	
Natural gas revenue per Mcf	$ 4.91		$ 4.16	
Less: Natural gas derivatives non cash amortization	(0.10)		—	
Natural gas derivative cash settlements (c)	0.30		—	
Average realized natural gas price per Mcf	$ 5.11		$ 4.16	

(a) *Includes non-cash amortization of frozen December 31, 2009 fair values resulting from January 1, 2010 discontinuing of hedge accounting, recorded in Oil and natural gas sales*
(b) *Includes cash settlements on derivatives prior to January 1, 2010, for which we had elected hedge accounting, recorded in Oil and natural gas sales*
(c) *Includes cash settlements on derivatives subsequent to January 1, 2010, for which we had discontinued hedge accounting, recorded in Realized and unrealized gain (loss) on derivatives, net*

Sales of Oil and Natural Gas.

Oil and gas revenue increased 28% to $152 million in the second quarter of 2010 compared to $119 million in the second quarter of 2009. The increase is primarily due to a 12% increase in sales volumes and an increase in the average sales price to $50.81 per BOE in the second quarter of 2010 from $45.74 per BOE in the second quarter of 2009. Oil and gas revenue increased 3% in the second quarter of 2010 compared to the first quarter of 2010. The increase is primarily due to a 12% increase in sales volume offset by a decrease in the average sales price to $50.81 per BOE in the second quarter of 2010 from $55.99 per BOE in the first quarter of 2010. Approximately 67% of our oil and gas sales volumes in the second quarter of 2010 were crude oil, with 80% of the crude oil being heavy oil produced in California which was sold under various contracts with prices tied to the San Joaquin posted price.

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Oil and gas revenue increased 21% to $299 million in the six months ended June 30, 2010 compared to $247 million in the six months ended June 30, 2009. The increase is primarily due to an increase in the average sales price to $53.24 per BOE in the six months ended June 30, 2010 from $46.44 per BOE in the six months ended June 30, 2009.

Effective January 1, 2010, we elected to de-designate all of our commodity derivative contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. As a result of discontinuing hedge accounting on January 1, 2010, changes in fair values at December 31, 2009 are frozen in accumulated other comprehensive loss (AOCL) as of the de-designation date and will be reclassified into oil and gas revenues in future periods as the original hedged transactions affect earnings. As a result, in the three and six months ended June 30, 2010, we reclassified $4.1 million and $6.9 million, respectively, of non-cash derivative losses relating to de-designated commodity hedges from AOCL into earnings under the caption Sales of oil and gas. Beginning January 1, 2010 all of our derivative contract fair value gains and losses are recognized immediately in earnings as Realized and unrealized gain (loss) on derivatives, net. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded to earnings as Realized and unrealized gain (loss) on derivatives, net. See Realized and unrealized gain (loss) on derivatives, net below.

The average sales price for oil sales during the second quarter of 2010 was $63.02 per BOE, an increase of 7% or $4.26 per BOE compared to the second quarter of 2009. The average sales price for oil sales during the six months ended June 30, 2010 was $64.46 per BOE, an increase of 12% or $6.84 per BOE compared to the six months ended June 30, 2009. The range of NYMEX light sweet crude prices for the second quarter of 2010, based upon settlements, was from a low of $68.01 to a high of $86.84. NYMEX light sweet crude prices for the second quarter of 2009, based upon settlements, was a low of $45.88 and a high of $72.68. The range of NYMEX light sweet crude prices for the six months ended June 30, 2010, based upon settlements, ranged from a low of $68.01 to a high of $86.84. NYMEX light sweet crude prices for the six months ended June 30, 2009, based upon settlements, had a low of $33.98 and a high of $72.68. In California the differential on June 30, 2010 was $6.82 and ranged from a low of $6.82 to a high of $8.95 per barrel during the second quarter of 2010. The California differential ranged from a low of $6.45 to a high of $8.18 per barrel during the second quarter of 2009. The California differential ranged from a low of $6.82 to a high of $8.95 per barrel during the six months ended June 30, 2010. In Utah, we are a party to a crude oil sales contract through June 30, 2013 with a refiner for the purchase of our Uinta light crude oil. Pricing under the contract, which includes transportation and gravity adjustments, is at a fixed percentage of WTI. While the contractual differentials under this contract may be less favorable at times than the posted differential, demand for our 40 degree black wax (light) crude oil can vary seasonally and this contract provides a stable outlet for our crude oil.

The average sales price for gas sales during the second quarter of 2010 was $4.43 per Mcf, an increase of 39% or $1.25 per Mcf compared to the second quarter of 2009. The average sales price for gas sales during the six months ended June 30, 2010 was $4.91 per Mcf, an increase of 18% or $0.75 per Mcf compared to the six months ended June 30, 2009. We sell our produced natural gas at various indices. Henry Hub (HH) natural gas averaged $4.09 in the second quarter of 2010, $3.51 in the second quarter of 2009, $4.70 in the six months ended June 30, 2010 and $4.21 in the six months ended June 30, 2009. As of mid-2009, the pricing of our Piceance basin natural gas production is tied to the eastern markets in Lebanon or Clarington, Ohio, which averaged $0.12 above HH for the second quarter of 2010 and $0.16 above HH for the six months ended June 30, 2010. The Piceance basin natural gas was sold in the six months ended June 30, 2009 based upon a mid-continent index such as PEPL, which averaged $0.24 below HH in the second quarter of 2009 and averaged $1.21 below HH in the six months ended June 30, 2009. Correspondingly, most of the Uinta basin natural gas is sold based on a Questar index which averaged $0.53 below HH for the second quarter of 2010 and $1.12 below HH for the second quarter of 2009. The Questar index averaged $0.40 and $1.42 below HH for the six months ended June 30, 2010 and 2009, respectively. The E. Texas natural gas production was generally sold during the six months ended June 30, 2010 at the Florida Zone 1 index which was the same as HH for the second quarter and six months ended June 30, 2010. The E. Texas natural gas production was sold during the six months ended June 30, 2009 at the Texas Eastern - East Texas index, which averaged $0.20 below HH for the second quarter of 2009 and $0.21 below HH for the six months ended June 30, 2009.

Sales of Electricity.

Electricity revenues increased in the second quarter of 2010 compared to the second quarter of 2009 due to an increase in sales volume and an increase in electricity prices. Electricity operating costs increased in the second quarter of 2010 compared to the second quarter of 2009 due to an increase in fuel gas cost. Electricity revenues decreased in the second quarter of 2010 compared to the first quarter of 2010 due to a 7% decrease in sales volumes and a 16% decrease in electricity prices. Electricity operating costs decreased in the second quarter of 2010 compared to the first quarter of 2010 due to a 22% decrease in fuel gas cost. We purchased approximately 26 MMBtu/D and 28 MMBtu/D of natural gas as fuel for use in our cogeneration facilities for the three months ended June 30, 2010 and March 31, 2010, respectively.

Electricity revenues increased in the six months ended June 30, 2010 compared to the six months ended June 30, 2009 as a result of an increase in sales volume. Electricity operating costs increased in the six months ended June 30, 2010 compared to the six months ended June 30, 2009 due to 36% higher fuel gas cost.

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	Three months ended			Six months ended	
	June 30, 2010	June 30, 2009	March 31, 2010	June 30, 2010	June 30, 2009
Electricity					
Revenues (in millions)	$ 7.9	$ 6.6	$ 9.9	$ 17.9	$ 16.9
Operating costs (in millions)	$ 7.8	$ 6.4	$ 9.7	$ 17.5	$ 15.2
Electric power produced - MWh/D	2,009	2,007	2,154	2,081	2,049
Electric power sold - MWh/D	1,840	1,783	1,979	1,909	1,860
Average sales price/MWh	$ 47.47	$ 46.99	$ 56.17	$ 53.18	$ 53.14
Fuel gas cost/MMBtu (including transportation)	$ 4.18	$ 3.12	$ 5.39	$ 4.80	$ 3.54

Natural Gas Marketing.

We have long-term firm transportation contracts for our Piceance natural gas production, with total capacity of 35,000 MMBtu/D. We pay a demand charge for this capacity and our own production does not currently fill that capacity. In order to maximize our firm transportation, we bought our partners' share of the gas produced in the Piceance at the market rate for that area. We used our excess transportation to move this gas to where it was eventually sold. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Income (Loss) for the three months ended

June 30, 2010 and 2009 is $0.6 million. The pre-tax net of our gas marketing revenue and our gas marketing expense in the Condensed Statements of Income (Loss) for the six months ended June 30, 2010 and 2009 is $1.1 million and $0.9 million. Firm transportation costs related to all of our Rockies Express volumes is reflected in Operating costs - oil and gas production and total $3.7 million and $2.5 million for the three months ended June 30, 2010 and 2009, respectively and $6.9 million and $5.0 million for the six months ended June 30, 2010 and 2009, respectively.

Realized and unrealized gain (loss) on derivatives, net.

Realized and unrealized gain (loss) on derivatives, net is primarily related to derivatives for which we did not elect hedge accounting or derivatives which did not qualify for cash flow hedge accounting either at their inception or where hedge accounting was discontinued during their term. When the criteria for cash flow hedge accounting is not met, or when cash flow hedge accounting is not elected, realized gains and losses (i.e., cash settlements) are recorded in Realized and unrealized gain (loss) on derivatives, net in the Condensed Statements of Income (Loss). Similarly, changes in the fair value of the derivative instruments are recorded as unrealized gains or losses in the Realized and unrealized gain (loss) on derivative, net in the Condensed Statements of Income (Loss). In contrast, cash settlements for derivative instruments that qualify for hedge accounting are recorded as additions to or reductions of oil and gas revenues, while changes in fair value of cash flow hedges are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Realized and unrealized gain (loss) on derivatives, net also includes any hedge ineffectiveness on cash flow hedges that qualify for hedge accounting.

During 2009, we entered into certain commodity derivative contracts that we did not designate as cash flow hedges. In addition, effective January 1, 2010, we elected to de-designate all of our commodity and interest rate derivative contracts that had been previously designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. Accordingly, beginning January 1, 2010 derivative contract fair value gains and losses are recognized immediately in earnings. Cash flow is impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded to earnings under the caption Realized and unrealized gain (loss) on derivatives, net.

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The following table sets forth the cash settlements and non-cash mark-to-market adjustments for the derivative contracts not designated as hedges recorded in Realized and unrealized gain (loss) on derivatives, net for the periods indicated:

	Three months ended			Six months ended	
	June 30, 2010	June 30, 2009	March 31, 2010	June 30, 2010	June 30, 2009
Cash receipts (payments):					
Commodity derivatives - oil	$ 21	$ —	$ (414)	$ (393)	$ —
Commodity derivatives - natural gas	2,757	—	517	3,274	—
Financial derivatives - interest	(1,829)	—	(1,826)	(3,655)	—
Mark-to-market gain (loss):					
Commodity derivatives - oil	$ 58,852	$ (7,436)	$ (7,112)	$ 51,741	$ (7,275)
Commodity derivatives - natural gas	(2,888)	(1,030)	11,939	9,051	(1,030)
Financial derivatives - interest	(856)	—	(1,501)	(2,357)	—
Total Realized and unrealized gain (loss) on derivatives, net for items not under hedge accounting	$ 56,057	$ (8,466)	$ 1,603	$ 57,661	$ (8,305)

For the three and six months ended June 30, 2009, a portion of the change in fair value for hedges that we have designated as cash flow hedges impacts our income as our sales price was not perfectly correlated with our hedges. As a result, for the three months ended June 30, 2009, we recognized an unrealized net loss of approximately $22.6 million on the Condensed Statement of Income (Loss) under the caption Realized and unrealized gain (loss) on derivatives, net. In the six months ended June 30, 2010, we reclassified a gain of $14.3 million from AOCL to the Condensed Statements of Income (loss) under the caption Realized and unrealized gain (loss) on derivatives, net. The $14.3 gain was in conjunction with the first quarter 2009 sale of the DJ basin assets, in which we concluded that the forecasted transaction in certain of our hedging relationships was not probable.

Settlement in Flying J bankruptcy.

On July 6, 2010, that certain Joint Plan of Reorganization of Flying J, Inc., Big West of California, LLC, Big West Oil, LLC, Big West Transportation, LLC and Longhorn Partners Pipeline, L.P. was confirmed under Chapter 11 of the United State Bankruptcy Code. Additionally, on July 6, 2010, the United States Bankruptcy Court approved and confirmed the June 15, 2010 Stipulation and Agreed Order (the Stipulation) with Flying J Inc. and certain of its affiliates (collectively Flying J), regarding the resolution of our claim in Flying J's pending bankruptcy. Pursuant to the Stipulation, we and Flying J agreed that the total amount owed to us by Flying J was $60.5 million. We received $60.5 million in cash on July 23, 2010. In the second quarter ended June 30, 2010, we recorded a settlement of our Flying J bankruptcy claim of $22.0 million and a bad debt recovery of $38.5 million. See Notes 12 and 13 to the Condensed Financial Statements.

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Oil and Gas Operating and Other Expenses. The following table presents information about our continuing operating expenses for each of the three month periods ended:

	Amount per BOE			Amount (in thousands)		
	June 30, 2010	June 30, 2009	March 31, 2010	June 30, 2010	June 30, 2009	March 31, 2010
Operating costs — oil and gas production	$ 15.54	$ 13.03	$ 17.78	$ 46,452	$ 34,738	$ 47,036
Production taxes	1.69	1.83	1.97	5,064	4,885	5,204
DD&A — oil and gas production	14.62	12.89	13.57	43,703	34,371	35,907

G&A	4.07	4.94	5.23	12,155	13,164	13,835
Interest expense	5.47	3.97	6.60	16,340	10,589	17,447
Total	$ 41.39	$ 36.66	$ 45.15	$ 123,714	$ 97,747	$ 119,429

· Operating costs in the second quarter of 2010 were $46.5 million or $15.54 per BOE, compared to $34.7 million or $13.03 per BOE in the second quarter of 2009 and $47.0 million or $17.78 per BOE in the first quarter of 2010. Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information:

	June 30, 2010 (2Q10)	June 30, 2009 (2Q09)	2Q10 to 2Q09 Change	March 31, 2010 (1Q10)	2Q10 to 1Q10 Change
Average volume of steam injected (Bbl/D)	110,467	107,739	3%	118,733	(7)%
Fuel gas cost/MMBtu (including transportation)	$ 4.18	$ 3.12	34%	$ 5.39	(22)%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	33,501	29,459	14%	36,699	(9)%

The increase in operating costs compared to the second quarter of 2009 is primarily due to a 34% increase in fuel gas costs as a result of increased natural gas prices and a 14% increase in fuel gas volume consumed in steam generation. The decrease in operating costs compared to the first quarter of 2010 is primarily due to a 22% decrease in fuel gas costs as a result of decreased natural gas prices and a 9% decrease in fuel gas volume consumed in steam generation.

· Production taxes in the second quarter of 2010 were $5.1 million or $1.69 per BOE, compared to $4.9 million or $1.83 per BOE in the second quarter of 2009 and $5.2 million or $1.97 per BOE in the first quarter of 2010. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. The decrease in production taxes, on a per barrel basis, compared to the second quarter of 2009 is due to a decrease in the assessed ad valorem tax values attributed to our California properties. The decrease in production taxes, on a per barrel basis, compared to the first quarter of 2010 is primarily related to well incentives claimed on various severance tax filings and decreases in assessed ad valorem tax values attributed to our Texas properties.

· Depreciation, depletion and amortization (DD&A) in the second quarter of 2010 was $43.7 million or $14.62 per BOE, compared to $34.4 million or $12.89 per BOE in the second quarter of 2009 and $35.9 million or $13.57 per BOE in the first quarter of 2010. The increase in DD&A in the second quarter of 2010 compared to both the second quarter of 2009 and the first quarter of 2010 is primarily due to the increase in production from assets outside of California which have higher per barrel DD&A rates than our California properties.

· General and administrative expense (G&A) in the second quarter of 2010 was $12.2 million or $4.07 per BOE, compared to $13.2 million or $4.94 in the second quarter of 2009 and $13.8 million or $5.23 per BOE in the first quarter of 2010. The decrease in G&A in the second quarter of 2010 compared to the second quarter of 2009 is due to the liability that was established in the second quarter of 2009 for a regulatory compliance matter, offset by an increase resulting from additional headcount due to staffing of the Permian asset team. The decrease in G&A in the second quarter of 2010 compared to the first quarter of 2010 is due to director compensation paid in the first quarter of 2010. Approximately 65% of our G&A is related to compensation.

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· Interest expense in the second quarter of 2010 was $16.3 million or $5.47 per BOE, compared to $10.6 million or $3.97 per BOE in the second quarter of 2009 and $17.4 million or $6.60 per BOE in the first quarter of 2010. The increase in interest expense compared to the second quarter of 2009 was due to the issuance of our 10.25% senior notes due 2014, in May 2009. The amortization of the net discount and deferred loan costs attributable to the senior notes is also included in interest expense. Interest expense decreased compared to the first quarter of 2010 primarily due to an increase in interest costs capitalized in the second quarter of 2010 compared to the first quarter of 2010. Additionally, in the second quarter of 2010, we reclassified $2.4 million, or $0.80 per BOE of non-cash derivative losses relating to de-designated interest rate hedges from AOCL into earnings. Interest expense in the second quarter of 2010 was $4.67 per BOE, excluding the non-cash derivative losses.

The following table presents information about our continuing operating expenses for each of the six month periods ended:

	Amount per BOE		Amount (in thousands)	
	June 30, 2010	June 30, 2009	June 30, 2010	June 30, 2009
Operating costs — oil and gas production	$ 16.59	$ 13.39	$ 93,488	$ 72,122
Production taxes	1.82	1.96	10,269	10,537
DD&A — oil and gas production	14.13	13.14	79,609	70,769
G&A	4.61	4.91	25,990	26,457
Interest expense	6.00	3.83	33,788	20,639
Total	$ 43.15	$ 37.23	$ 243,144	$ 200,524

· Operating costs in the six months ended June 30, 2010 were $93.5 million or $16.59 per BOE, compared to $72.1 million or $13.39 per BOE in the six months ended June 30, 2009. Steam costs are the primary variable component of our operating costs and fluctuate based on the amount of steam we inject and the price of fuel used to generate steam. The following table presents steam information for each of the six months periods ended:

	June 30, 2010	June 30, 2009	Change
Average volume of steam injected (Bbl/D)	114,577	105,118	9%
Fuel gas cost/MMBtu (including transportation)	$ 4.80	$ 3.54	36%
Approximate net fuel gas volume consumed in steam generation (MMBtu/D)	35,097	27,887	26%

The increase in operating costs is primarily due to a 36% increase in fuel gas costs as a result of increased natural gas prices and a 26% increase in fuel gas volume consumed in steam generation.

- Production taxes in the six months ended June 30, 2010 were $10.3 million or $1.82 per BOE, compared to $10.5 million or $1.96 per BOE in the six months ended June 30, 2009. Severance taxes paid in Utah, Colorado and Texas are directly related to the field sales price of the commodity. In California, our production is burdened with ad valorem taxes on our total proved reserves. The decrease in production taxes compared to the six months ended June 30, 2009 is due to a decrease in the assessed ad valorem tax values attributed to our California properties.

- Depreciation, depletion and amortization (DD&A) in the six months ended June 30, 2010 was $79.6 million or $14.13 per BOE, compared to $70.8 million or $13.14 per BOE in the six months ended June 30, 2009. The increase in the six months ended June 30, 2010 compared to the six months ended June 30, 2009 is primarily due to the increase in production from assets outside of California which have higher per barrel DD&A rates than our California properties.

- General and administrative expense (G&A) in the six months ended June 30, 2010 was $26.0 million or $4.61 per BOE, compared to $26.5 million or $4.91 in the six months ended June 30, 2009.

- Interest expense in the six months ended June 30, 2010 was $33.8 million or $6.00 per BOE, compared to $20.6 million or $3.83 per BOE in the six months ended June 30, 2009. The increase in interest expense compared to the six months ended June 30, 2009 was due to the issuance of our 10.25% senior notes due 2014, in May 2009. The amortization of the net discount and deferred loan costs attributable to the senior notes is also included in interest expense. Additionally, in the six months ended June 30, 2010, we reclassified $5.1 million, or $0.91 per BOE, of non-cash derivative losses relating to de-designated interest rate hedges from AOCL into earnings. Interest expense in the six months ended June 30, 2010 was $5.09 per BOE, excluding the non-cash derivative losses.

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2010 Guidance.

For 2010 the Company is issuing the following guidance:

	Anticipated Range per BOE in 2010 ($/BOE)		
	$60 WTI/$4 HH	$60 WTI/$5 HH	$75 WTI/$6 HH
Operating costs-oil and gas production	$ 16.00 – 17.00	$ 17.00 – 18.00	$ 18.00 – 19.00
Production taxes	1.75 – 2.25	1.75 – 2.25	2.00 – 2.50
DD&A — oil and gas production		14.00 – 16.00	
G&A		4.00 – 4.50	
Interest expense		5.00 - 6.50	
Total		$ 41.75 – 47.25	

Transaction costs on acquisitions. In the three and six months ended June 30, 2010, transaction costs on acquisitions were $1.9 million and $2.6 million, respectively. In the three and six months ended June 30, 2010, we recorded $0.5 million and $2.6 million of acquisition related expenses, respectively, for the acquisition of certain properties in the Permian basin. The March 2010 acquisition had an effective date of January 1, 2010 and the activity from January 1, 2010 through March 4, 2010 was treated as purchase price adjustments. Our preliminary purchase price allocation included an estimate for the activity between January 1, 2010 and March 4, 2010; however, actual amounts were greater than our estimate which resulted in an increase to the total cash consideration paid to the seller. As a result, the initial $1.4 million of Gain on purchase of oil and natural gas properties recorded in the first quarter of 2010 has been reversed in the second quarter of 2010 to reflect the purchase price adjustments.

Dry hole, abandonment, impairment and exploration. In the three and six months ended June 30, 2010 we incurred dry hole, abandonment, impairment and exploration expense of $0.3 million and $1.6 million, respectively, which was primarily a result of mechanical failure encountered on one well in the Piceance basin. The well was abandoned in favor of drilling a replacement well from the same well pad. During the three months ended June 30, 2009, we did not incur any dry hole, abandonment, impairment and exploration expense. During the six months ended June 30, 2009 we had dry hole, abandonment, impairment and exploration charges of $0.1 million.

Loss on discontinued operations. On March 3, 2009, we entered into an agreement to sell our DJ basin assets and related hedges for $154 million before customary closing adjustments. The closing date of the sale of our DJ basin assets was April 1, 2009. We recorded an impairment charge of $9.6 million, which is aggregated within loss from discontinued operations, net of tax, on the Condensed Statement of Income (Loss) for the six months ended June 30, 2009.

Income Tax Expense. The effective income tax rate for the three months ended June 30, 2010 and 2009 was 38.1% and 36.1%, respectively. The effective income tax rate for the six months ended June 30, 2010 and 2009 was 37.9% and 33.0%, respectively. The increase in rate is primarily due to a one-time reduction in state deferred rates and uncertain tax positions in the prior periods. Reductions in the rate during prior periods were the result of acquisitions in more tax favorable jurisdictions that reduced future state tax obligations, as well as favorable state tax incentives. Our estimated annual effective tax rate varies from the 35% federal statutory rate due to the effects of state income taxes and estimated permanent differences. See Note 10 to the Condensed Financial Statements.

Drilling Activity. The following table sets forth certain information regarding drilling activities (including operated and non-operated wells):

	Three months ended June 30, 2010		Six months ended June 30, 2010	
Asset Team	Gross Wells	Net Wells	Gross Wells	Net Wells
S. Midway	26	25	53	52
N. Midway	3	3	17	17
Permian	4	4	5	5
Uinta	26	23	38	35
E. Texas	2	2	4	4
Piceance	6	4	9	6
Totals	67	61	126	119

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Properties

We currently have six asset teams as follows: South Midway-Sunset (S. Midway), North Midway-Sunset including diatomite (N. Midway), Permian, Uinta, E. Texas and Piceance. Our S. Midway asset team is primarily focused on production and generates significant cash flow to fund our planned drilling inventory in our N. Midway, Piceance, E. Texas, Uinta and W. Texas projects.

S. Midway — This asset team is responsible for our S. Midway leases including Homebase, Formax and Ethel D, as well as our Poso Creek property. In the second quarter of 2010 we drilled 26 wells, almost all of which focused on enhancing our thermal recovery at the Homebase and Formax leases. These new wells are currently on production and are performing in line with expectations. The balance of the wells drilled included several steam injection and observation wells at Poso Creek. Average daily production in the second quarter of 2010 from all S. Midway assets was approximately 12,076 BOE/D, a 3% increase from the first quarter of 2010.

N. Midway — Our N. Midway asset team includes our Diatomite, Placerita and McKittrick assets and several N. Midway-Sunset leases. Our diatomite production in the second quarter was 2,730 BOE/D. The production decline in the diatomite compared to the first quarter of 2010 is due to the inability to drill new wells as we await permits and certain operational changes we have implemented to facilitate higher production volumes when development drilling resumes. We continue to invest in infrastructure for the diatomite. There is no update on when we will be able to resume drilling new wells in the diatomite. However, we are currently working with the DOGGR on an interim solution that would allow diatomite development to resume in the last half of 2010. We continue to evaluate McKittrick and are encouraged with the results to date. Average daily production in the second quarter of 2010 from all N. Midway assets was approximately 5,414 BOE/D.

Permian — Our Permian asset team executed a one rig drilling program in the second quarter of 2010 and we plan to execute a three rig drilling program for the remainder of 2010, increasing production over the course of the year. We now have an inventory of over 200 drilling locations on forty-acre spacing in the Wolfberry trend. We have opened a Midland, Texas office and have fully staffed our Permian asset team. Average daily production in the second quarter of 2010 was approximately 1,033 BOE/D.

Uinta — In the second quarter of 2010, production from our Uinta basin assets averaged 5,217 BOE/D. We drilled 26 wells with a two rig drilling program, targeting higher oil potential areas of Brundage Canyon and Lake Canyon. The Ashley Forest Development EIS continues to progress and the draft EIS public comment period ended in the second quarter of 2010. Approval of the final EIS is anticipated in the next six to nine months. Our drilling inventory in the Uinta is approximately 300 locations distributed between Brundage Canyon, the Ashley Forest and Lake Canyon.

E. Texas — In the second quarter of 2010, production from our E. Texas assets averaged 31.0 MMcfe/D. We continue to operate a one rig program which is now drilling horizontal Haynesville wells in our Darco field located in Harrison County. In the second quarter of 2010 we successfully drilled two additional horizontal wells and completed three horizontal wells. As of June 30, 2010 we had four Haynesville wells completed and online. Lateral lengths have ranged from 4,257 feet to 4,590 feet and have been completed between 13 and 16 fracture stimulation treatments. Well performance on our second and third wells for the first 30 days average production has ranged from 9 to 10 MMcf/D per well.

Piceance — In the second quarter of 2010, production from the Piceance basin averaged 23.6 MMcfe/D. We continued to operate a one rig drilling program focusing on remaining lease earning obligations. We drilled 6 wells in the second quarter and continued to utilize improved completions techniques with 4 new well completions and 6 uphole recompletions in the second quarter. Results from these completions continue to meet our expectations.

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Financial Condition, Liquidity and Capital Resources

Our exploration, development, and acquisition activities require us to make significant operating and capital expenditures. Historically, we have used cash flow from operations and our bank credit facilities as our primary sources of liquidity. We have also used the debt and equity markets as other sources of financing and, as market conditions have permitted, we have engaged in asset monetization transactions.

Changes in the market prices for oil and natural gas directly impact our level of cash flow generated from operations. We employ derivative instruments in our risk management strategy in an attempt to minimize the adverse effects of wide fluctuations in the commodity prices on our cash flow. As of June 30, 2010 we had approximately 75% and 45% of our expected 2010 and 2011 oil production, respectively, hedged with derivative instruments in the form of swaps and collars and we had approximately 30% and 20% of our 2010 and 2011 expected natural gas production, respectively , hedged with derivative instruments in the form of swaps and collars. This level of derivatives is expected to provide a measure of certainty of the cash flow that we will receive for a portion of our production in 2010 and 2011. In the future, we may determine to increase or decrease our derivative positions. Most of our derivatives counterparties were commercial banks that are parties to our credit facilities, or their affiliates. See Item 3, “Quantitative and Qualitative Disclosures About Market Risk” for further details concerning our hedging activities.

We have a $1.5 billion senior secured revolving credit facility with a current borrowing base of $938 million and $601 million of available borrowing capacity. At June 30, 2010, we had $310 million in borrowings and $24 million in letters of credit outstanding under the credit facility. Our borrowing base is subject to semi-annual redeterminations in April and October of each year and was reconfirmed in April 2010. The borrowing base is determined by the lenders (a syndicate of banks), taking into consideration the estimated value of our proved oil and gas reserves based on pricing models determined by the lenders. In addition, we may borrow up to $30 million for a maximum of 30 days under our Secured Line of Credit. There was $3.3 million outstanding on the Secured Line of Credit at June 30, 2010 and no outstanding borrowings at December 31,2009. See Note 9 to the Condensed Financial Statements.

We received $60.5 million in cash upon settlement of our Flying J bankruptcy claim on July 23, 2010. We used the proceeds from the settlement to reduce outstanding borrowings under our senior secured revolving credit facility, which increased our available borrowing capacity to over $650 million.

The debt and equity markets have served as our primary source of financing to fund large acquisitions and other transactions. In January 2010, we sold to the public 8 million shares of our common stock at a price of $29.25 per share and received $224 million of net proceeds after deducting the underwriting discounts and the offering expenses. We used the net proceeds to fund the March Acquisition and to reduce our outstanding borrowings under our senior secured revolving credit facility. In May 2009, we issued $325 million principal amount of 10.25% senior notes due 2014 and in August 2009 we issued an additional $125 million principal amount of our 10.25% senior notes due 2014. See Note 9 to the Condensed Financial Statements.

Our ability to access the debt and equity capital markets on economical terms is affected by general economic conditions, the financial markets, the credit ratings assigned to our debt by independent credit rating agencies, our operational and financial performance, the value and performance of equity and debt securities, prevailing commodity prices, and other macroeconomic factors outside of our control.

We also have engaged in asset dispositions as a means of generating additional cash to fund expenditures and enhance our financial flexibility. For example, in April 2009, we sold our DJ basin assets and related hedges for $154 million before customary closing adjustments and in July 2009 we completed the sale of our E. Texas gathering system for $18 million in cash.

Cash Flows

Operating activities - Net cash flows provided by operating activities are primarily affected by the price of crude oil and natural gas, production volumes, and changes in working capital. The increase in net cash provided by operating activities of $75.7 million in the first six months of 2010 compared to the first six months of 2009 is primarily due to higher realized commodity sales prices in the first six months of 2010 compared to the first six months of 2009.

Investing Activities - Cash flows used by investing activities are primarily comprised of acquisition, exploration and development of oil and gas properties net of dispositions of oil and gas properties. Net cash used in investing activities in the first six months of 2010 primarily consisted of the Permian Basin Acquisitions. Net cash provided by investing activities in the first six months of 2009 primarily consisted of proceeds from the sale of the DJ basin assets in 2009.

Financing Activities - Net cash provided by financing activities in the first six months of 2010 included proceeds from the issuance of stock of $224.3 million, the net repayment of borrowings under our senior secured revolving credit facility and our Secured Line of Credit of $58.7 million and dividends paid of $8.1 million. Net cash used in financing activities in the first six months of 2009 included the net repayment of borrowings under our senior secured revolving credit facility and our Secured Line of Credit of $376.2 million, debt issuance costs of $21.5 million and dividends paid of $6.8 million, offset by the net proceeds from the issuance of 10¼% senior notes of $304.0 million.

Capital Expenditures

We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. We may revise our capital budget during the year as a result of acquisitions and/or drilling outcomes or significant changes in cash flows. In 2010, we are expecting a capital program of up to $290 million, and we expect to fully fund this program from operating cash flow. Our capital expenditures for the second quarter of 2010 totaled $87.1 million for development and capitalized interest of $7.1 million compared to total capital expenditures for the second quarter of 2009 of $22.9 million for development and capitalized interest of $7.3 million. Our capital expenditures for the six months ended June 30, 2010 totaled $135.0 million for development and capitalized interest of $13.1 million compared to total capital expenditures for the six months ended June 30, 2009 of $73.1 million for development and capitalized interest of $12.6 million. We expect our 2010 capital program will allow us to increase production from 2009 levels to average 2010 production between 32,250 BOE/D and 33,000 BOE/D.

We believe that our cash flow provided by operating activities and funds available under our credit facilities will be sufficient to fund our operating and capital expenditures budget and our short-term contractual operations during 2010. However, if our revenue and cash flow decrease in the future as a result of deterioration in economic conditions or an adverse change in commodity prices, we may have to reduce our spending levels. As we have operational control of all of our assets and we have limited drilling commitments, we believe that we have the financial flexibility to adjust our spending levels, if necessary, to meet our financial obligations.

Critical Accounting Policies and Estimates

Reference should be made to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2009 for a discussion of other critical accounting policies that we consider as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment by management.

Derivatives and Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We also enter into derivative contracts to mitigate the risk of interest rate fluctuations. The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge. Changes in fair value of a derivative designated as a cash flow hedge are recognized, to the extent the hedge is effective, in AOCL until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge, to the extent the hedge is effective, have no effect on the Condensed Statements of Income because changes in fair value of the derivative offsets changes in the fair value of the hedged item. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings. Hedge effectiveness is assessed at least quarterly based on total changes in the derivative’s fair value and any ineffective portion of the derivative instrument’s change in fair value is recognized immediately in earnings. The estimated fair value of our derivative instruments requires substantial judgment. These values are based upon, among other things, whether or not the forecasted hedged transaction will occur, option pricing models, futures prices, volatility, time to maturity and credit risk. The values we report in our Condensed Financial Statements changes as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond our control. Effective January 1, 2010, we have elected to de-designate all of our commodity and interest rate contracts that had previously been designated as cash flow hedges as of December 31, 2009 and have elected to discontinue hedge accounting prospectively. At December 31, 2009, AOCL consisted of $97 million ($60 million after tax) of unrealized losses, representing the fair value of our cash flow hedges as of the Condensed Balance Sheet date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on January 1, 2010, such changes in fair values at December 31, 2009 are frozen in AOCL as of the de-designation date and will be reclassified into earnings in future periods as the original hedged transactions affect earnings. We expect to reclassify into earnings from AOCL the frozen value related to de-designated commodity hedges during the next three years. See Note 4 to the Condensed Financial Statements.

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Recent Accounting Standards and Updates

In January 2010, the FASB issued Accounting Standards Update (ASU) No. 2010-06 "*Improving Disclosures about Fair Value Measurements.*" The ASU amends previously issued authoritative guidance and requires new disclosures and clarifies existing disclosures and is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the rollforward activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010 and for interim periods within those fiscal years. As this requires only additional disclosures, the guidance will have no impact on our financial position or results of operations.

Reconciliation of Non-GAAP Measures

Discretionary Cash Flow

In addition to reporting cash provided by operating activities as defined under GAAP, we present discretionary cash flow, which is a non-GAAP liquidity measure. Discretionary cash flow consists of cash provided by operating activities before changes in working capital items. Management uses discretionary cash flow as a measure of liquidity and believes it provides useful information to investors because it assesses cash flow from operations for each period before changes in working capital, which fluctuates due to the timing of collections of receivables and the settlements of liabilities. The following table provides a reconciliation of cash provided by operating activities, the most directly comparable GAAP measure, to adjusted discretionary cash flow for the period presented.

(in millions)	**For the Three Months Ended June 30, 2010**	**For the Three Months Ended June 30, 2009**
Net cash provided by operating activities	$ 71.4	$ 51.1
Add back: Net increase (decrease) in current assets	19.0	(5.0)
Add back: Net decrease in current liabilities including book overdraft	12.8	8.8
Add back: Recovery of Flying J bad debt	38.5	—
Discretionary cash flow	$ 141.7	$ 54.9

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Berry Petroleum Company
Quantitative and Qualitative Disclosures About Market Risk

Item 3. Quantitative and Qualitative Disclosures About Market Risk

As discussed in Note 3 to the Condensed Financial Statements, to minimize the effect of a downturn in oil and gas prices and protect our profitability and the economics of our development plans, we enter into crude oil and natural gas derivative contracts from time to time. The terms of contracts depend on various factors, including management's view of future crude oil and natural gas prices, acquisition economics on purchased assets and our future financial commitments. This price hedging program is designed to moderate the effects of a severe crude oil and natural gas price downturn while allowing us to participate in some commodity price increases. In California, we benefit from lower natural gas pricing, as we are a consumer of natural gas in our operations, and elsewhere we benefit from higher natural gas pricing. We have hedged, and may hedge in the future, both natural gas purchases and sales as determined appropriate by management. Management regularly monitors the crude oil and natural gas markets and our financial commitments to determine if, when, and at what level some form of crude oil and/or natural gas hedging and/or basis adjustments or other price protection is appropriate and in accordance with policy established by our board of directors. Currently, our derivatives are in the form of swaps and collars. However, we may use a variety of derivative instruments in the future to hedge WTI or the index gas price. A two-way collar is a combination of options, a sold call and purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be NYMEX plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (the ceiling) we will receive for the volumes under contract. We utilize costless collars which is an options position by which the proceeds from the sale of the call option fund the purchase of a put option.

In total, we have approximately 75% and 45% of our expected 2010 and 2011 oil production, respectively, hedged in the form of swaps and collars. In total, we have approximately 30% and 20% of our 2010 and 2011 expected natural gas production, respectively, hedged in the form of swaps and collars. A ten dollar change in oil prices impacts our annual operating cash flow by approximately $8 million. A one dollar change in natural gas prices impacts annual operating cash flow by approximately $2 million.

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The following table summarizes our commodity derivative position as of June 30, 2010:

Term	**Average Barrels Per Day**	**Average Prices**

Crude Oil Sales (NYMEX WTI) Two-Way Collars		
Full year 2010	1,000	$65.15 / $75.00
Full year 2010	1,000	$65.50 / $78.50
Full year 2010	280	$80.00 / $90.00
Full year 2010	1,000	$100.00/$161.10
Full year 2010	1,000	$100.00/$150.30
Full year 2010	1,000	$100.00/$160.00
Full year 2010	1,000	$100.00/$150.00
Full year 2010	1,000	$100.00/$158.50
Full year 2010	1,000	$70.00/$86.00
Full year 2010	500	$75.00/$93.95
Full year 2010	500	$75.00/$94.45
Full year 2011	270	$80.00 / $90.00
Full year 2011	1,000	$55.20/$70.00
Full year 2011	1,000	$55.00 / $70.50
Full year 2011	1,000	$55.00/$68.65
Full year 2011	1,000	$55.00/$68.00
Full year 2011	1,000	$55.00/$71.20
Full year 2011	1,000	$60.00/$76.00
Full year 2011	1,000	$60.00/$81.25
Full year 2011	500	$75.00/$100.75
Full year 2011	500	$75.00/$101.15
Full year 2011	1,000	$75.00/$91.25
Full year 2012	1,000	$63.00/$82.60
Full year 2012	1,000	$63.00/$83.50
Full year 2012	1,000	$70.00/$93.00
Full year 2012	500	$75.00/$105.00
Full year 2012	500	$75.00/$106.00
Full year 2012	1,000	$75.00/$95.00
Crude Oil Sales (NYMEX WTI) Three-Way Collars		
Full year 2011	1,000	$60.00/$80.00/$101.00
Full year 2012	1,000	$60.00/$80.00/$120.00
Crude Oil Sales (NYMEX WTI) Swaps		
Full year 2010	1,000	$61.00
Full year 2010	1,000	$61.25
Full year 2010	1,000	$64.80
Full year 2010	1,000	$62.03
Full year 2010	1,000	$63.00
Full year 2010	1,000	$63.75
Full year 2010	650	$56.90
Full year 2011	500	$57.36
Full year 2011	500	$57.40
Full year 2011	500	$57.50
Full year 2011	250	$61.80
Natural Gas Sales (NYMEX HH) Two-way Collars		
Full year 2010	2,000	$6.00/$8.60
Full year 2010	3,000	$6.00/$8.65
Full year 2010	1,000	$6.50/$8.75
Full year 2010	1,000	$6.50/$8.85
Full year 2010	2,000	$6.50/$8.90

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Full year 2011	5,000	$6.00/$7.25
Full year 2012	5,000	$6.00/$7.70
Natural Gas Sales (NYMEX HH TO PEPL) Basis Swaps		
Full year 2010	2,000	$1.05
Full year 2010	3,000	$1.00
Natural Gas Sales (NYMEX HH TO NGPL) Basis Swaps		
Full year 2010	2,000	$0.49
Natural Gas Sales (NYMEX HH TO HSC) Basis Swaps		
Full year 2010	2,000	$0.38
Full year 2010	2,500	$0.35
Full year 2011	2,500	$0.33
Full year 2012	2,500	$0.32
Natural Gas Sales (NYMEX HH TO NGPL-Tex OK) Basis Swaps		

Full year 2010	2,500	$0.42
Full year 2011	2,500	$0.46
Full year 2012	2,500	$0.44
Natural Gas Sales (NYMEX HH) Swaps		
Full year 2010	5,000	$5.73
Full year 2010	5,000	$6.02
Full year 2011	5,000	$5.50
Full year 2011	5,000	$6.89
Full year 2012	5,000	$5.75
Full year 2012	5,000	$7.16

The related cash flow impact of all of our derivatives is reflected in cash flows from operating activities.

Based on average NYMEX futures prices as of June 30, 2010 (WTI $79.43; HH $5.49) for the term of our derivatives we would expect to make pre-tax future cash payments or to receive payments over the remaining term of our crude oil and natural gas derivatives in place as follows:

	June 30, 2010 NYMEX Futures	Impact of percent change in futures prices on pre-tax future cash (payments) and receipts			
		-40%	-20%	+ 20%	+40%
Average WTI Futures Price (2010 — 2012)	$ 79.43	$ 47.66	$ 63.54	$ 95.31	$ 111.20
Average HH Futures Price (2010 — 2012)	5.49	3.29	4.39	6.59	7.68
Crude Oil gain/(loss) (in millions)	$ (29.9)	$ 196.2	$ 66.9	$ (129.4)	$ (227.7)
Natural Gas gain/(loss) (in millions)	11.6	54.1	34.5	(1.0)	(16.2)
Total	$ (18.3)	$ 250.3	$ 101.4	$ (130.4)	$ (243.9)
Net pre-tax future cash (payments) and receipts by year (in millions) based on average price in each year:					
2010 (WTI $76.45; HH $4.94)	5.3	103.8	53.0	(35.7)	(75.4)
2011 (WTI $79.31; HH $5.46)	(28.1)	76.0	20.4	(87.2)	(147.7)
2012 (WTI $81.03; HH $5.79)	4.5	70.5	28.0	(7.5)	(20.8)
Total	$ (18.3)	$ 250.3	$ 101.4	$ (130.4)	$ (243.9)

Interest Rates. Our exposure to changes in interest rates results primarily from long-term debt. In October 2006, we issued, in a public offering, $200 million principal amount of 8.25% senior subordinated notes due 2016. In May 2009, we issued, in a public offering, $325 million of 10.25% senior notes due 2014. In August 2009, we issued, in a public offering, an additional $125 million of 10.25% senior notes due 2014. At June 30, 2010, total long-term debt outstanding was $947.7 million. Interest on amounts borrowed under our credit facility is charged at LIBOR plus 2.25% to 3.0% plus the credit facility's margin through July 15, 2012. Based on June 30, 2010 credit facility borrowings, a 1% change in interest rates, including our interest rate derivatives, would have an annualized $0.4 million after tax impact on our Condensed Financial Statements.

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We have entered into interest rate derivatives as shown below to swap the floating rate under our senior secured credit facility (LIBOR) for a fixed interest rate.

Derivative Term	Notional Amount $MM	Fixed Rate
4/1/2009 — 6/30/2012	100	4.74%
4/15/2009 — 7/15/2012	100	1.99%
9/15/2009 — 7/15/2012	50	2.31%

As of June 30, 2010, as a result of our interest rate derivative contracts and the Notes, we have a total of $900 million of fixed rate positions averaging 7.8%.

Berry Petroleum Company
Controls and Procedures

Item 4. Controls and Procedures

As of June 30, 2010, we have carried out an evaluation under the supervision of, and with the participation of, our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934, as amended.

Based on their evaluation as of June 30, 2010, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e)) under the Securities Exchange Act of 1934) are effective to ensure that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and include controls and procedures designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

There was no change in our internal control over financial reporting that occurred during the three months ended June 30, 2010 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We may make changes in our internal control procedures from time to time in the future.

Forward Looking Statements

"Safe harbor under the Private Securities Litigation Reform Act of 1995:" Any statements in this Form 10-Q that are not historical facts are forward-looking statements that involve risks and uncertainties. Words such as "plan," "will," "intend," "continue," "target(s)," "expect," "achieve," "future," "may," "could," "goal(s)," "anticipate," "estimate" or other comparable words or phrases, or the negative of those words, and other words of similar meaning indicate forward-looking statements and important factors which could affect actual results. Forward-looking statements are made based on management's current expectations and beliefs concerning future developments and their potential effects upon Berry Petroleum Company. These items are discussed at length in Part I, Item 1A on page 17 of our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010, under the heading "Risk Factors" and all material changes are updated in Part II, Item 1A within this Form 10-Q.

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Berry Petroleum Company
Signature

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

While we are, from time to time, a party to certain lawsuits in the ordinary course of business, we do not believe any of such existing lawsuits will have a material adverse effect on our operations, financial condition, or liquidity.

Item 1A. Risk Factors

For additional information about our risk factors, see Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 25, 2010.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Removed and Reserved

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit No.	Description of Exhibit
10.1*	Berry Petroleum Company 2010 Equity Incentive Plan (filed as Exhibit 4.3 to the Registrant's Form S-8 filed on June 23, 2010, File No. 333-167698).
10.2*	Berry Petroleum Company 2010 Equity Incentive Plan — Form of Restricted Stock Unit Agreement (filed as Exhibit 4.4 to the Registrant's Form S-8 filed on June 23, 2010, File No. 333-167698).
10.3*	Berry Petroleum Company 2010 Equity Incentive Plan — Form of Restricted Stock Unit Agreement — Officers (filed as Exhibit 4.5 to the Registrant's Form S-8 filed on June 23, 2010, File No. 333-167698).
10.4*	Berry Petroleum Company 2010 Equity Incentive Plan — Form of Restricted Stock Unit Agreement — Directors (filed as Exhibit 4.6 to the Registrant's Form S-8 filed on June 23, 2010, File No. 333-167698).
10.5*	Berry Petroleum Company 2010 Equity Incentive Plan — Form of Stock Option Agreement (filed as Exhibit 4.7 to the Registrant's Form S-8 filed on June 23, 2010, File No. 333-167698).
10.6*	Berry Petroleum Company 2010 Equity Incentive Plan — Form of Stock Appreciation Rights Agreement (filed as Exhibit 4.8 to the Registrant's Form S-8 filed on June 23, 2010, File No. 333-167698).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document**
101.SCH	XBRL Taxonomy Extension Schema Document**
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document**
101.LAB	XBRL Taxonomy Label Linkbase Document**
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document**
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document**

* Incorporated herein by reference
** To be filed by amendment

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereto duly authorized.

BERRY PETROLEUM COMPANY

/s/ Jamie L. Wheat
Jamie L. Wheat
Controller
(Principal Accounting Officer)
Date: August 9, 2010

Exhibit 12.1

COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

(in thousands, except ratios)

	Six Months Ended June 30, 2010	12/31/09	12/31/08	12/31/07	12/31/06	12/31/05
Pre-tax income from continuing operations	$ 171,936	$ 88,317	$ 192,084	$ 206,344	$ 159,906	$ 150,289
Interest expense	33,788	50,738	26,209	17,287	10,247	6,048
Capitalized interest	13,054	30,107	23,209	18,104	9,339	—
Earnings	$ 205,724	$ 139,055	$ 218,293	$ 223,631	$ 170,153	$ 156,337
Ratio of earnings to fixed charges	4.4	1.7	4.4	6.3	8.7	25.8

For purposes of this table, “earnings” consists of income before income taxes from continuing operations plus fixed charges and less capitalized interest. “Fixed charges” consists of interest expense and capitalized interest (for both continuing and discontinued operations).

Exhibit 31.1

Certification of Chief Executive Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, Robert F. Heinemann, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, and its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ Robert F. Heinemann

Robert F. Heinemann

President, Chief Executive Officer and Director

August 9, 2010

Exhibit 31.2

Certification of Chief Financial Officer

Pursuant to Section 302 of Sarbanes Oxley Act of 2002

I, David D. Wolf, certify that:

1. I have reviewed this report on Form 10-Q of Berry Petroleum Company (the Company);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of, and for, the periods presented in this report;

4. The Company's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a - 15(e) and 15d - (e) and internal control over financial reporting (as defined in Exchange Act Rules 13a - 15(f) and 15d - 15(f)) for the Company and have:

   a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Company, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designated under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) evaluated the effectiveness of the Company's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

   d) disclosed in this report any change in the Company's internal control over financial reporting that occurred during the Company's most recent fiscal quarter that has materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting;

5. The Company's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the Company's auditors and the audit committee of the Company's board of directors:

   a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Company's ability to record, process, summarize and report financial information; and

   b) any fraud, whether or not material, that involves management or other employees who have a significant role in the Company's internal controls over financial reporting.

/s/ David D. Wolf

David D. Wolf
Executive Vice President and Chief
Financial Officer

August 9, 2010

Exhibit 32.1

Certification of Chief Executive Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the “Company”) on Form 10-Q for the period ended June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Robert F. Heinemann, President, Chief Executive Officer and Director of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Robert F. Heinemann

Robert F. Heinemann

President, Chief Executive Officer and Director

August 9, 2010

Exhibit 32.2

Certification of Chief Financial Officer

Pursuant to Section 906 of Sarbanes Oxley Act of 2002

In Connection with the Quarterly Report of Berry Petroleum Company (the “Company”) on Form 10-Q for the period ended June 30, 2010 as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, David D. Wolf, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. 1350, as adopted pursuant to 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ David D. Wolf
David D. Wolf
Executive Vice President and Chief Financial Officer

August 9, 2010